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ENVIRONMENTAL STATEMENT

For a Proposed
1973 OUTER CONTINENTAL SHELF
OIL AND GAS GENERAL LEASE SALE
OFFSHORE MISSISSIPPI, ALABAMA, AND FLORIDA

OCS SALE NO. 32
FES 73-60

Volume 3 of 5

Alternatives to the Proposed Action

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Prepared by the
BUREAU OF LAND MANAGEMENT
U.S. DEPARTMENT OF THE INTERIOR

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VIII. ALTERNATIVES TO THE PROPOSED ACTION

A. Hold the Sale in Modified Form

1. Details of Tract Selection Process for Proposed MAFLA Sale

The Mississippi, Alabama, and Florida call for nominations resulted in approximately 8-3/4 million acres (1500 blocks) being nominated by 30 companies out of over 24 million acres available. The tract selection process sets forth an orderly, systematic procedure by which the 8-3/4 million acres were reduced to a logical, reasonable sale size, as determined by present Departmental guidelines (600,000-1,000,000 acres).

Three primary leasing objectives or Departmental goals have been established for the OCS program. These objectives are: orderly resource development, protection of the environment, and receipt of fair market value. These three objectives are necessarily broad, but require specific application in the tract selection process.

These general categories were specifically applied as follows:

a. Nominations and Past Leasing History

No leasing history exists for any of the selected tracts since this was the first call for nomination in this frontier area.

Unweighted and weighted nominations were scrutinized to identify, as closely as possible, implied geologic structures. These nominations were then balanced against GS technical geologic and geophysical interpretations for further refinement.

b. Geology

BLM-New Orleans forwarded to GS-New Orleans the initial tract selections with a request for GS to review these tracts using expertise available to them.

GS covered in detail the quality of geophysical data, type of data, extent of knowledge and data coverage, potential prospects and stratigraphic trends and application and reliability of geophysical interpretation.

c. Environmental Considerations

The preliminary environmental analysis was presented in the general form of physical, resource and socio-economic profiles, using map overlays and written documentations.

The categories of information presented include:

1. Ocean currents & Wind
2. Basic Geology
3. Bottom Sediments
4. Hazards

5. Outdoor Recreation
6. Sport fishing
7. Commercial Finfish
8. Commercial Benthos
9. Commercial Shrimp
10. Rare and/or Endangered Species
11. Upland Wildlife
12. Upland Birds
13. Waterfowl Concentrations
14. Livestock and Grazing
15. Transportation
16. Lands and Waters of Ecological Importance
17. Lands "Suitable" for Development
18. Socio-Economic

The above basic information was then interpreted as to the potential impact on, or hazard to, the individual resource from offshore drilling and development, pipeline construction and oil spillage. From these interpretations "potential environmental hazard zones" were developed in the tract selection process. In addition other factors considered were as follows:

d. Special Considerations

(1) Defense Warning Areas

Warning zones were identified which affect the call for nominations area and the possibility of conflict between leasing and warning area uses was considered. Acreage and nominations, both in and out of the warning areas, were analyzed for possible inclusion or exclusion.

(2) Sale Size

Departmental guidelines, based on supply-demand and potential reserve estimates, have established approximately 600,000-1,000,000 acres as the sale size. The tract selections in this case conform to those guidelines.

(3) Frontier Area

Selections were in relatively wide geographic areas that would tend to maximize future evaluation and development in a frontier area. Even though the areas are relatively widespread geographically, they meet other requirements of tract selection, i.e., high nominations and structurally and geologically attractive.

(4) Other

Consideration in tract selection was given to economics, including industry economics, national economics, and regional economics.

The high industry interest in offshore MAFLA, measured by level of nominations, expresses industry's desire to explore and develop this frontier area. Special attention was given to tracts receiving a large number of nominations because this is an indicator that several companies view these tracts as having economically feasible production potential. For this reason, number of nominations received is always an important factor in tract selection.

The proposed leasing of MAFLA tracts is an item on the tenative five-year schedule. The schedule attempts to relate timing, size and location of each sale to the projected national needs for hydrocarbons. Production from this area would, to an extent, lessen our import needs and thereby ease the balance of payments strain. As to the choice of specific tracts in the tract selection process, the objective of orderly resource development received high priority. An attempt was made to select desirable tracts over a large area so that if and when they are leased, our geologic information and knowledge of type and extent of production will be greatly increased for planning future sales.

There is a large potential for substantial impact on the regional economies should leasing begin in the MAFLA area. However, consideration of impact on regional economics was not a factor in the initial selection of specific tracts for proposed leasing.

In summary the tracts selected for further consideration for leasing and analyzed for potential environmental impact in this statement are believed at this time to have the highest geologic potential for oil and gas production, highest estimated reserves and offer the most efficient resource exploitation. The potential environmental impact of leasing these tracts has been previously described in this impact statement.

2. Sale Modification Alternatives

a. Delete Tracts With High Environmental Risk Potential

Tracts could be deleted which are identified by matrix analysis to have the relatively highest potential of environmental risk. All tracts are judged at this time to be prospectively valuable for both oil and gas production and are considered to range from high to moderate in potential for environmental risk. A total of 35 tracts are tentatively considered at this time to have high environmental risk potential as defined in this impact statement. 1/ Of those tracts that are considered to have moderate environmental risk potential some are relatively higher than others principally due to closer proximity to specific resource areas and use conflicts.

The 35 tracts tentatively identified as highly hazardous and any specific number of the moderately hazardous tracts could be eliminated

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1/ See section III. K.

from the sale and this would correspondingly reduce the overall potential environmental impact of the proposed sale. Deletion from this proposed sale of the 35 tracts (i.e., Tract Nos. 67 through 113 listed on Attachment B) in the Pensacola South No. 1 area would eliminate any hazard potential associated with military uses of the area. Reserve estimates after all tracts in the Pensacola South No. 1 area are removed would range from .7-1.1 billion bbl. of oil and .9-1.3 tcf of gas. Elimination of any tracts, however, would result in the loss from this sale of estimated recoverable reserves of oil and gas which would have to be made up from some other source.

b. Delete Tracts in the Pensacola, Appalachicola and Tampa-Tarpon Springs Areas Pending Completion of Base Line Data Collection and Analysis

All tracts offshore Florida could be deleted from the proposed offering pending the completion of base line data collection and analysis. This alternative would reduce the reserves from this proposal by 60 to 70 percent and would delay the development of the reserves of this area. It would eliminate any presently known potential environmental impact associated with the development of these tracts and would provide additional detailed data for the analysis of the potential environmental impact of offering these tracts at some future date.

In addition to deleting all tracts offshore Florida, comments were received recommending tracts be deleted in each of the three areas offshore Florida pending further analysis and data and/or better technology and protection from oil spills. Deletion of any of these areas would decrease the environmental impact as assessed in this statement and would result in a decrease in reserves forthcoming from this proposed sale. The relative ranking of each tract in the proposed sale by potential environmental risk is contained in Section III. K., Summary Risk Analysis and Appendix F - Matrix Appendix.

c. Substitute Tracts

Tracts with relatively lower potential environmental risk could be substituted for those of high potential risk. Such action would not necessarily result in less total activity or environmental effect since more acreage and blocks would be required to meet minimum resource estimates. This would result in more exploratory drilling, more platforms constructed, additional miles of pipelines required and a substantial increase in production activities with attendent increase in potential adverse environmental impacts discussed in detail throughout this environmental statement for these activities.

In all probability potential environmental benefits of substituting tracts with lower environmental risk and lower resource estimates may not be realized due to increased acreage and exploratory activity required.

B. Withdraw the Sale

In addition to modification of the proposed sale, all tracts could be withdrawn from leasing consideration. A decision to withdraw the sale completely or to seriously limit the number of tracts to be leased would diminish the contribution of OCS gas and oil toward meeting future energy demand, and would subsequently necessitate development of alternative sources of energy, with their associated environmental impacts. These impacts can be found in the assessment of possible short-term alternatives on the following pages.

The production from tracts projected from leasing at this sale would also represent a significant contribution to meeting domestic energy needs. The sale is expected to contribute to the supply of relatively short-run energy requirements (i.e., 5 to 15 years). Few alternatives exist to help offset the need for domestic oil and gas during this period. The alternatives discussed below are those which may help meet projected energy demands in the event the proposed sale is withdrawn.

The following is a list of energy sources or actions which, if implemented, might be considered as alternatives to offshore oil and gas. Long term sources, as well as short term sources, of energy will be discussed.

1. Energy Conservation
2. Conventional Oil and Gas Supplies
3. Coal
4. Synthetic Sources of Gas and Oil
5. Hydroelectric Power
6. Nuclear Power
7. Energy Imports
8. Other Energy Sources
9. Combination of Alternatives

The approach used in analysis of each alternative has been to review the technology involved in realizing the energy from the source; the resource base of the energy inputs; economic considerations such as supply and demand schedules, cost and price projections, state of development; environmental impacts; and relationship of the alternative to the proposed OCS sale. This last section includes the amount of the alternative required to supply the energy that would not be provided if the proposed sale were not held and restrictions on the substitutability of the alternative for OCS oil and gas. Some of the problems to industries in substitution of another fuel for natural gas were enumerated in comments of the United Distribution Companies on the draft statement for the East Texas General OCS sale. They are as follows:

(a) Conversion to a liquid fuel involves construction of facilities for storing an inventory of oil as well as related piping, pumps and heaters, even where liquid fuel can do the job.

(b) The capacity of production equipment is sometimes reduced when fired by a fuel other than gas, e.g., the melt in a glass furnace must be reduced when a fuel more luminous than natural gas is burned, and similar difficulties may result if ammonia plants switch from methane to heavier feed stocks. This may result in up to 25% lost capacity in such plants.

(c) Breakage or spoilage increases in certain industrial processes where less desirable fuels are substituted for natural gas. This problem occurs in refractory manufacture of metallurgical processes.

(d) Maintenance costs increase in certain industrial applications when gas is replaced by even a high grade liquid fuel. This is true, as one example, in the operation of turbines.

(e) Natural gas is used as process fuel in many plants and its replacement would be most difficult from a technological point of view. For example, in ammonia reforming furnaces temperature distributions within the furnace are critical so that the different flame characteristics produced by oil create operating problems. Also, the sulphur and ash content of the fuel must be very low in order to minimize tube corrosion in the presence of extremely high temperatures. It has been estimated that for a plant with a rated capacity of 1,000 tons of ammonia per stream day, or 340,000 tons per year, additional investment outlays of approximately $450,000 would be required to convert from natural gas to liquid fuel.

(f) Natural gas has special qualities in the metallurgical industry where exact temperature controls, low flame emissitivity, convective heat transfer and minimization of hot spots are important. Heat treating and annealing furnaces cannot easily be converted from natural gas to other fuels.

(g) In most cases, equipment will need to be modified and, in some cases totally replaced, in order to accommodate a different fuel. Complete replacement of direct flame makeup air heaters for a paint drying line in the automotive industry could entail a new investment equal to 150% or more of the price of the replaced gas burning heaters.

(h) Natural gas provides approximately half of the petrochemical industry's supply of feed stocks and economic dislocations can be expected if it is no longer available.

(i) In the manufacture of cement, natural gas has technical advantages not only because gas firing rates are easier to control, but also because cement must not contain excessive amounts of sulphur and sulphur is already present in the raw material before it enters the kilns.

Supporting analyses for developing the tentative five-year leasing schedule, the linear transportation model for natural gas is useful in determining the extent to which some of the energy alternatives can be regarded as actual substitutes for the estimated oil and gas production from the proposed sale. The linear transportation model for natural gas allocates projected supplies of natural gas to consumer demand regions on the basis of least cost and identifies national and regional supply gaps. It gives an indication of what regions OCS natural gas production serves and where the large deficits will exist. In some instances, the distance of an alternative source of energy from the projected consuming region which would be served by the proposed MAFLA sale production precludes that alternative as an actual substitute for the OCS production. This is discussed under the specific alternatives.

Other limitations on substitutability include technology, high development and production costs, and time lag before the alternative could be a viable technical option. In early stages of development of an alternative source of energy, it may serve more as a supplement than as a substitute. Furthermore, there are some cases in which substitutability is diminished because of the projected use of the offshore oil and gas. These limitations are noted in the individual alternative discussions when applicable.

The discussion of these alternatives as presented below includes a consideration of the possibility of energy conservation as a method which might decrease or eliminate some of the energy requirements to be satisfied by this sale. A table has also been prepared showing the incremental production potential of the alternatives considered and the possibility of having a combination of sources substitute for the proposed sale.

There are additional potential energy sources which hold great promise for the future. They are not, however, sources which are considered to be reasonably available to meet short-run energy demand, since their utilization will depend on future technologic development, economics, and adequate environmental safequards.

The following table shows the equivalents which will be used in this discussion. When production has stabilized, the proposed MAFLA sale may result in 270,000-443-000 barrels of oil per day and 0.34-0.52 billion cubic feet of natural gas per day. Using common conversion factors, this level of production is first expressed in Btu's and then in terms of the other important energy sources. The electrical equivalents were determined by considering two cases. The maximum requirement for generating capacity would result when the substitution of electrical energy for oil and gas occurred at the end use point. The minimum case is the result of substituting electrical energy produced by an alternative source for the electrical energy produced by the oil and gas.

Btu Equivalents 1/ (Trillion Btu/day)			
Oil	1.566	-	2.569
Natural Gas	.351	-	.537
Total	1.917		3.106
Oil (barrels/day)			
Directly replace expected oil production	270,000	-	443,000
Substitute for expected gas production	60,500	-	92,500
Total	330,500		535,500
Natural Gas (billion cu.ft./day)			
Directly replace expected gas production	0.34	-	0.52
Substitute for expected oil production	1.52	-	2.49
Total	1.86		3.01
Coal (million tons/year)	29		47
Electrical Equivalents (Megawatts of capacity)			
Substitution at end use 2/	20,000	-	33,000
Substitution as input to electrical generation 3/	11,000	-	18,000

1/ Conversion factors used:

1 barrel - oil = 5.8×10^6 Btu
1 cubic foot - natural gas = 1,032 Btu
1 ton - coal = 24×10^6 Btu
1 kilowatt - hour = 3,412 Btu

2/ Based on oil and gas fired units operating at 60% efficiency and plants were assumed to operate 70% of the time.

3/ Efficiency of fossil fuel electrical generation was assumed to be 33%.

1. Energy Conservation

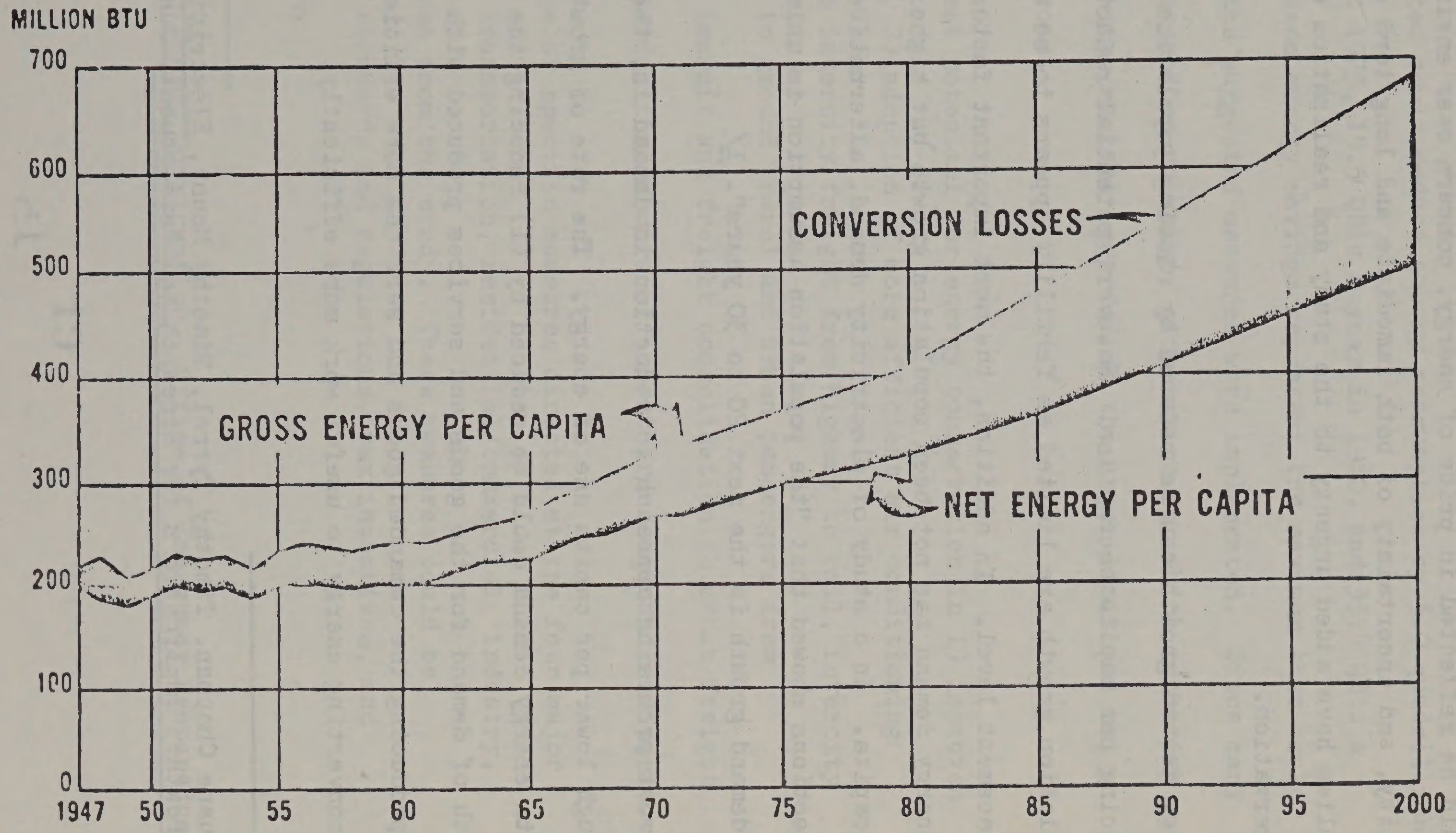
The United States has both the highest per capita consumption of energy and the highest per capita income in the world. Energy has provided the foundation for a continued rise in our material standard of living. Demand for energy in the U. S. has been increasing at an average rate of 3.1% annually for the last twenty years, more than twice the growth rate of the U. S. population. Higher energy use per capita compounded by population growth has produced unprecedented levels of energy consumption. As population growth slows, increasing per capita demand will account for a larger and larger share of increasing total demand for energy. These trends are illustrated in Table I-12 and Figure I-1.

Table I-12: U. S. Total and Per Capita Net and Gross Energy Inputs

Year	Gross Energy Input quadrillion Btu's	Net Energy Input	population millions	Gross Energy Input Per Capita million Btu's	Net Energy Input Per Capita million Btu's
1950	34.0	29.7	152.3	223.2	194.8
1955	39.7	34.3	165.9	239.3	206.7
1960	44.6	38.2	180.7	246.8	211.5
1965	53.3	45.3	194.2	274.4	232.1
1970	67.4	56.0	204.8	329.1	273.6
1975	80.3	65.1	216.2	371.4	301.2
1980	96.0	76.1	229.4	418.5	330.8
1985	116.6	89.7	243.3	479.2	369.9
2000	191.9	140.1	279.7	686.1	500.9

Source: United States Energy Through the Year 2000. USDI, December, 1972.

UNITED STATES NET AND GROSS ENERGY INPUTS PER CAPITA
1947 - 2000
(MILLIONS OF BTU's)



Source: U. S. Energy Through the Year 2000, U. S. Dept. of Interior, Dec., 1972, p. 5.

In the past, energy growth has been little constrained by price or by supply of resources. However, recognition that environmental costs should be reflected in price of energy, concern over environmental quality, and uncertainty of both immediate and long term energy supplies have added urgency to the study and realization of energy conservation.

Energy demand growth can be reduced by slowing population growth and reducing per capita energy use. However, potential reductions in population growth are limited as fertility appears to be approaching replacement level. In addition, the most important factor in growth of energy demand has not been population growth but higher energy use per capita. In a study of electricity demand, alternative population projections showed that "the population assumption is unimportant for demand growth in the next 20 to 30 years". 1/

The most promising approach to reduction in demand is, therefore, through lower per capita use of energy. The rate of growth of per capita energy demand could be reduced by (1) reducing the rate of growth of demand for the goods and services produced with energy, (2) producing the demanded goods and services more efficiently, and (3) converting energy to useful work more efficiently.

1/ Duane Chapman, Timothy Tyrrel, Timothy Mount, Electricity Demand Growth: Implications for Research and Development, June, 1972.

The Office of Emergency Preparedness recently released a study on energy conservation. 1/ The study focuses particularly on short-term and mid-term user conservation measures and does not consider improvements in recovery techniques for primary fuels or related government actions. The measures suggested could reduce energy consumption by 5.0 quadrillion Btu (QBtu) a year in 1975, 15.5 QBtu a year in 1980, and 33.4 QBtu a year after 1980. These energy savings represent the maximum that could be achieved if all the suggested measures were implemented. Since many of the suggestions depend on voluntary cooperation for which incentive is slight, the estimates must be regarded as the upper limit and not the most likely outcome.

OEP found the greatest potential for energy conservation in 1) improved insulation in homes, 2) adoption of more efficient air conditioning systems, 3) shift to intercity freight from highway to rail, intercity passengers from air to ground travel and urban passengers from automobiles to mass transit and freight consolidation in urban freight movement, and 4) introduction of more efficient processes and equipment.

The following outline of specific measures directed at the four major consuming sectors - transportation, residential/commercial, industry, and utilities is taken from the study. These measures could be implemented through standards and regulations, tax incentives, and educational campaigns.

1/ The Potential for Energy Conservation. Office of Emergency Preparedness, October, 1972.

Short-Term Measures (1972-1975)

Transportation - Conduct educational programs to stimulate public awareness of energy conservation in the transportation sector; establish government energy efficiency standards; improve airplane load factors; promote development of smaller engines/vehicles; improve traffic flow; improve mass transit and intercity rail and air transport; promote automobile energy-efficiency through low loss tires and engine tuning.

Savings - 1.9 QBTU/yr.[1] (10 percent)

Residential/Commercial - Provide tax incentives and insured loans to encourage improved insulation in homes; encourage use of more efficient appliances and adoption of good conservation practices.

Savings - 0.2 QBTU/yr. (1 percent)

Industry - Increase energy price to encourage improvement of processes and replacement of inefficient equipment; provide tax incentives to encourage recycling and reusing of component materials.

Savings - 1.9-3.5 QBTU/yr. (6-11 percent)

Electric Utilities - Smooth out daily demand cycle by means of government regulation; facilitate new construction; decrease electricity demand.

Savings - 1.0 QBTU/yr. (4 percent) (already assumed in the projections)

Mid-Term Measures (1976-1980)

Transportation - Improve freight handling systems; support pilot implementation of most promising alternatives to internal combustion engine; set tax on size and power of autos; support improved truck engines; require energy-efficient operating procedures for airplanes; provide subsidies and matching grants for mass transit; ban autos within the inner city; provide subsidies for intercity rail networks; decrease transportation demand through urban refurbishing projects and long range urban/suburban planning.

Savings - 4.8 QBTU/yr. (21 percent)

Residential/Commercial - Establish upgraded construction standards and tax incentives and regulations to promote design and construction of energy-efficient dwellings including the use of the "total energy concept" for multi-family dwellings; provide tax incentives, R&D funds and regulations to promote energy efficient appliances, central air conditioning, water heaters, and lighting.

Savings - 5.1 QBTU/yr. (14 percent)

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[1] Quadrillion BTU.

Industry - Establish energy use tax to provide incentive to upgrade processes and replace inefficient equipment; promote research for more efficient technologies; provide tax incentives to encourage recycling and reusing component materials.

Savings - 4.5-6.4 QBTU/yr. (12-17 percent)

Electric Utilities - Restructure rates for heavy uses to smooth out demand cycle; facilitate new construction.

Savings - 1.1 QBTU/yr. (4 percent) (already assumed in the projections)

Long-Term Measures (beyond 1980)

Transportation - Provide R&D support for hybrid engines, non-petroleum engines, advanced traffic control systems, dual mode personal rapid transit, high speed transit, new freight systems, and people movers; decrease demand through rationing and financial support for urban development and reconstruction.

Savings - 8 QBTU/yr. (25 percent)

Residential/Commercial - Provide tax incentives and regulations to encourage demolition of old buildings and construction of energy-efficient new buildings; R&D funding to develop new energy sources (solar, wind power).

Savings - 15 QBTU/yr. (30 percent)

Industry - Establish energy use tax to provide incentive for upgrading processes and replacing inefficient equipment; promote research in efficient technologies; provide tax incentives to encourage recycling and reusing component materials.

Savings - 9-12 QBTU/yr. (15-20 percent)

Electric Utilities - Smooth out daily demand cycle through government regulation; facilitate new construction; support R&D efforts.

Savings - 1.4 QBTU/yr. (3 percent)

The Office of Emergency Preparedness estimates that by 1980 space heating and cooling requirements could be reduced by 20% through improved insulation and a nationwide education program to encourage conservation practices in the home. Thermal insulation also reduces the energy required for air conditioning, an important factor in summer peak loads of utility systems. Different models of air conditioners vary greatly in efficiency. The least efficient consumes 2.6 times the electricity consumed by the most efficient to provide the same cooling. If more efficient air conditioners were used, the annual power consumption for air conditioning in 1970 could have been reduced by 15.8 billion Kwh, or about 40%. The connected load would have also been decreased by 40%, or by 17,800 MW. 1/

In his Energy Message of April 18, 1973, President Nixon told the Nation:

> "To provide consumers with further information, I am directing the Department of Commerce, working with the Environmental Protection Agency, to develop a voluntary system of energy efficiency labels for major home appliances. These labels should provide data on energy use as well as a rating comparing the product's efficiency to other similar products".

1/ Eric Hurst and John C. Moyers, Improving Efficiency of Energy Use: Transportation and Space Heating and Cooling, written testimony submitted to the House Subcommittee on Science, Research and Development, June, 1972.

A step forward was taken in 1971 with the revision of the Federal Housing Authority's Minimum Property Standards (MPS) for single family dwellings. The MPS establishes thermal design criteria for qualification of residences for FHA-insured mortages. However, new homes constructed through conventional financing are not required to follow these standards. The revised FHA-MPS do not distinquish between electrically heated and combustion heated homes. A study of construction practices found that appreciable energy savings and some monetary savings to homeowners were possible through stricter insulation requirements. Wider application of these standards and additional insulation beyond the MPS requirements would afford further energy savings.

Substantial reductions are also possible in the transportation sector. The transportation of people and goods comprised 24.5% of U. S. energy consumption in 1970. Increases in transportation energy consumption are due primarily to growth in levels of traffic and shifts to less energy efficient modes. Tables I-13 and I-14 show energy requirements for transport of freight and passengers. The efficiencies are typical of the mid-1960's.

Table I-13

Freight Transport	Efficiency of Freight Btu/ton mile
Pipeline	450
Waterway	540
Railroad	680
Truck	2,300
Airplane	37,000

Table I-14

Passenger Transport	Efficiency of Passenger Btu/passenger-mile
Bicycle	200
Walking	300
Buses	1,200
Railroads	1,700
Automobile	4,500
Airplane	9,700

Source: Energy Consumption for Transportation in the U. S., Eric Hurst, Oak Ridge National Laboratory, June, 1971.

The shift from railroads to truck and airplane in freight traffic and from railroad and buses to airplanes has caused declining energy efficiency. The trend is encouraged by preferential government policies favoring air and highway transport. Low average car occupancy, use of cars for many short trips, and disregard for congestion problems increase fuel consumption and pollution.

In order to illustrate possible energy savings through use of energy efficient transport modes, one study compared two transportation models, an actual and a hypothetical case. Comparison of the two models revealed that adoption of the hypothetical case would require only 71% as much energy as the actual 1970 case. 1/

Assumptions underlying the hypothetical model include the following:

1) Half the freight traffic carried by conventional methods (truck and air) is to be carried by rail.

2) Half the inter-city passenger traffic carried by air and one-third the traffic transported by car are to be carried by bus and train.

3) All the urban automobile traffic is to be carried by bus.

Socio-economic factors which might inhibit shifts to the energy efficient transport modes employed in the conjectural model are ignored in the analysis. Such factors include: existing land use patterns, capital costs, changes in energy efficiency within a given mode, substitutability among modes, new technologies, transportation ownership patterns and other institutional variables.

1/ Improving Efficiency of Energy Use: Transportation and Space Heating and Cooling, op.cit.

A comparison between the actual and hypothetical models identifies the principal components of energy use patterns and emerging considerations which may precipitate the shift towards increased energy efficiency in urban transportation. Variables influencing the current energy mix include: personal preferences, private economics, convenience, speed, reliability and government policy. Current transportation patterns are altered by factors such as fuel scarcities, rising energy prices, dependence on foreign petroleum, urban land use problems, and environmental consideration.

The Office of Emergency Preparedness study estimated that short-term measures could produce a maximum energy savings in the transportation sector of 1.9 quadrillion Btu per year by 1975, equal to 10% of transportation demand. Such measures would include educational programs, establishment of government efficiency standards, improved airplane load factors, smaller engines and vehicles, improved mass transit, and improved traffic flow. Public awareness of energy conservation and alternatives would foster a clearer understanding of the energy implications of decisions. A change in public attitudes toward walking, bicycling, and mass transit, might do much to reduce demand for energy.

Another sector of great potential for energy conservation cited by the OEP study is industry. OEP projects that, with the exception of the primary metals sector, industrial demand for energy under existing technology could be reduced by 5 to 10% given sufficient economic incentives (possibly price increases or an energy tax). Often less efficient equipment is chosen because capital expenditure is recovered in a shorter time. Incentives for selection of more efficient equipment could counter higher capital expenditures. Industrial energy demand can also be cut by recycling metals. For non-ferrous metals the amount of energy required to recycle scrap metal is less than 20% of that required to refine the metal originally although new low energy primary metal extraction methods are in development.

The imbalance between supply and demand for energy can be narrowed through the price mechanism. In the past, use of natural air, water, and land resources has been virtually free. If a price were put on social costs reflecting depletion of resources and damage to the environment, energy patterns would tend to shift in order to reduce demand and conserve natural resources. For example, an electric rate schedule including higher charges for peak period usage would encourage consumers to shift use to other times of day, resulting in more efficient use of existing plants and less construction of new generating capacity to service peak demand. Tax credits and penalties could encourage development of cleaner and more efficient technology. For example, an auto tax would make it more expensive to drive a car and encourage use of mass transit.

Response of energy demand to increased in prices of energy is difficult to predict. In the short-term, gradually rising prices may have negligible effects. The study cited previously in the discussion of population growth concluded that "substantial cost increases and reduction in population growth will noticeably lower electricity demand growth in the 1980's and 1990's. Given the lengthy time period of response, growth reduction in the 1970's might be limited." 1/ The authors give the following preliminary estimates of elasticity of electricity demand for electricity prices, income, population, and gas prices.

Summary of Electricity Demand Estimated Elasticities
for Electricity Prices, Income, Population, and Gas Prices

Table I-15

Factor	Consumer Class Residential	 Commercial	 Industrial
Average Electricity Price	-1.3	-1.5	-1.7
Population	+ .9	+1.0	+1.1
Income	+ .3	+ .9	+ .5
Average Gas Price	+ .15	+ .15	+ .15
Percent of Response in First Year	10%	11%	11%
Years for 50% of Total Response	8 years	7 years	7 years

1/ Electricity Demand Growth: Implications for Research and Development, op.cit.

The elasticities of demand represent the relationship of the percentage change in electricity demand and the percentage change in the factor. For example, the commercial elasticity for electricity prices of -1.5 means that a 20% rise in average commercial electricity price would in the long run cause demand to be 30% less than it otherwise would have been.

The kind of public policies that would be required to reduce demand, according to Michael McCloskey, Executive Director of the Sierra Club, would include the replacement of the market system to determine how much energy shall be produced or imported and who shall consume energy, with a detailed control on the production, importation, and use of energy in all sectors and regions of the economy. In his evaluations relative to controlling energy growth, he states:

> "A short-run strategy would involve the following changes in public policy: ending or reducing the many biases in public policies which provide incentives to energy growth; maintaining and strengthening environmental constraints on energy growth; reducing energy demands by educating the public to understand the importance of conservative use of energy; encouraging intensified research and development in order to achieve greater efficiencies in energy utilization and in order to find new, more environmentally acceptable energy sources and discouraging

> growth in industries that are the most profligate consumers of energy. Coordination of these efforts would be facilitated through the establishment of new government agencies, specifically geared to respond to the energy problem. Each of these changes would involve efforts that would go well beyond the traditional bounds of energy policy, and all could have profound economic and social impacts. Yet changes are already beginning to occur in all these fields, and environmentalists are determined to promote them." 1/

To coordinate energy programs and carry out the directives of President Nixon's April 18, 1973 Energy Message, Secretary of the Interior Morton created four new offices on energy - the Office of Energy Conservation, the Office of Energy Data and Analysis, and the Office of Research and Development. The Office of Energy Conservation will promote consumer awareness of energy conservation, develop studies on measures to reduce energy requirements, coordinate all Federal agency programs relating to energy conservation, and work to obtain Federal, State, local and industry participation in energy-saving programs.

1/ Michael McCloskey, "The Energy Crisis: The Issues and a Proposed Response", Environmental Affairs, Vol. 1, No. 3, Nov. 1971, pp. 587-605.

Development of untapped energy sources and more efficient methods of energy conversion offer long-range possibilities for conservation of scarce non-renewable resources. Long-term sources such as geothermal steam, tar sands, hydrogen and solar energy, and conversion techniques such as the fuel cell and magnetohydrodynamics are discussed in separate sections.

The environmental benefits of energy conservation depend on the energy mix that evolves. Reduced consumption of energy from one or several sources may be balanced by increased consumption of energy from other sources. Environmental benefits will vary in direct proportion to the adverse impacts that would have resulted from the foregone consumption. Environmental impacts of each individual energy alternative are discussed in the section on that alternative. For example, curtailment of oil consumption will have greater environmental benefits than curtailment of gas consumption since oil combustion produces significant adverse environmental impacts while gas is virtually clean-burning.

If demand for energy could be reduced sufficiently, the projected oil and gas production from the proposed lease sale would be unnecessary. However, it is misleading to view the choices as either (1) producing 270 -443 thousand barrels of oil and 340-520 million cubic feet of gas per day from the MAFLA leases or (2) reducing demand for energy by this amount. Several considerations invalidate this reasoning: the widening gap between demand and supply of energy from all sources in the near future, the immediate shortage of natural gas and the need for oil to accomodate some of the unfulfilled demand for gas, and the limitations from the point of view of technology, cost, and time lag on substitution of other energy sources for oil and gas.

The shortage of natural gas is already evident. FPC estimates that demand for natural gas will exceed supply from all sources (including LNG, coal gas, and pipeline imports) by 3.6 trillion cubic feet in 1975, 9.5 trillion cubic feet in 1980, and 13.7 trillion cubic feet in 1985. The projected production from the lease sale of 340-520 million cubic feet a day, or 124-189 billion cubic feet a year, is equivalent to only 1.3 to 2.0 percent of estimated 1980 unsatisfied demand. Thus, only by reducing demand for natural gas by an amount greatly exceeding the projected lease production would such production be unnecessary.

2. Conventional Oil and Gas Supplies

Onshore oil and gas production

TECHNOLOGICAL PROCESSES 1/, 2/, 3/

The development and final utilization of oil and gas involves a wide range of operations, wherein the oil and gas must be found in a natural underground reservoir; lifted to the surface; transported to refineries; refined into more than a thousand products; and, finally, marketed and distributed.

Exploration

The first phase involves the location of petroleum reservoirs, which are generally found in porous sedimentary rocks. Favorable geologic conditions may result in a variety of traps which lead to the concentration of oil and gas. Three of the more common traps, known as "anticlinal"; "fault"; and "stratigraphic" traps, are illustrated in the following diagram:

1/ Breeding, Burke and Burton; 1972 Income Taxation of the Mineral Industry; pp. 103-112.

2/ Meadows, P., 1970 Petroleum in Staff, Bureau of Mines; Mineral Facts and Problems, U.S.B.M. Bulletin 650; pp. 147-182.

3/ Warner, A. J., 1970, "Natural Gas" in Staff, Bureau of Mines; Mineral Facts and Problems; U.S.B.M. Bulletin 650; pp. 111-136.

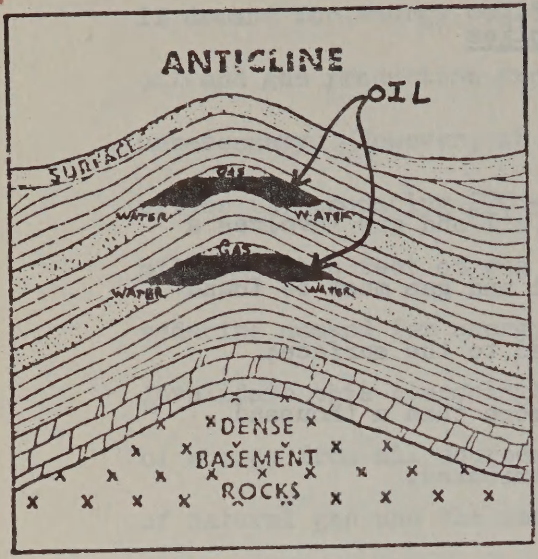


Fig. II-1

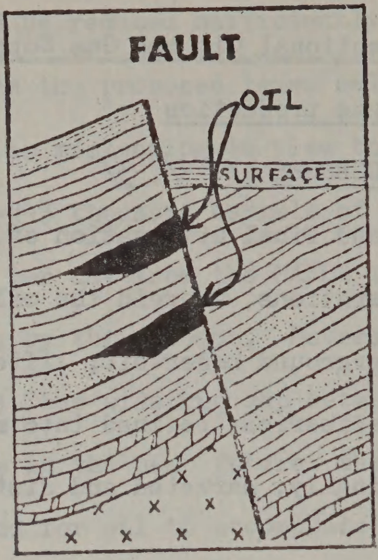


Fig. II-2

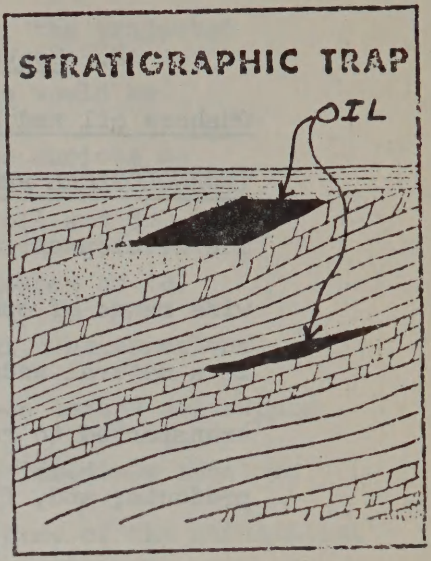


Fig. II-3

(From *Petroleum Discovery and Production,* pamphlet, American Petroleum Institute, New York, N.Y.)

These traps are initially located by a seismic survey. In seismic exploration an energy source generates a series of small amplitude seismic pulses that travel at thousands of feet per second through the earth and are reflected and refracted by the various subsurface strata. An array of sensitive geophones detects the returning seismic waves and records them on magnetic tape. These recordings are subject to highly sophisticated electronic data processing resulting in an end display of cross-sections and maps of the various subsurface formations and, hopefully, reveal - and locate - some of the above pictured traps. The final step in the exploration phase is the drilling of a "wildcat" well which is the actual proof of whether or not the suspected structure really exists and, if so, whether or not it is a trap and contains oil and/or gas.

Drilling

Once the existence of a commercial reserve (reservoir or field) of oil has been proved, the next phase is drilling a sufficient number of wells to develop the reservoir in the most profitable manner without wasting the resource.

The process of drilling and completing oil and gas wells on land is essentially the same as described in Section IF. A drilling rig is pictured in figure II-4.

Producing

Crude oil is brought to the surface from the subsurface reservoir by natural flow if there is sufficient pressure in the reservoir or by artificial means such as injection of high pressure gas or mechanical pumps. Gas, of course, is always brought to the surface by its own reservoir pressure.

Once the oil and/or gas has reached the surface, it is subjected to some treatment on the lease site to separate the oil from the gas and to remove water from both. After this initial treatment, crude oil goes to storage on the lease and later by pipeline to a refinery tank farm. Gas, on the other hand, usually enters a common carrier main pipeline direct from the lease.

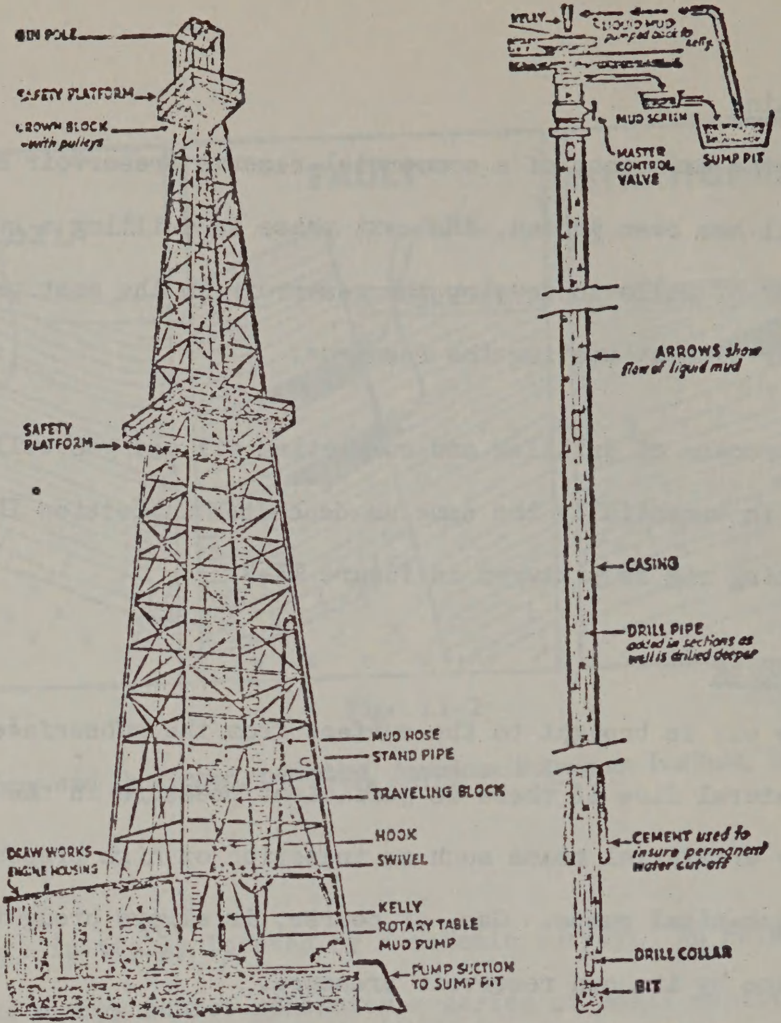


Fig. II-4 Rotary drilling rig.

Left: derrick—above ground.

Right: drilling operations—below ground.

"Draw Works" is the collective name for the hoisting drum, shaft, and clutches, and other operating machinery. Power is received from the engine. The rotary table is driven by a chain from the draw works and rotates the hollow drill stem, which drills the well. The drill stem, consisting of drill pipe, drill collar, and bit, is raised from or lowered into the well by a cable, which is wound on the hoisting drum and passes through a series of pulleys in the crown block. Casing, or lining for the well, is raised or lowered in the same manner. (From *Petroleum Discovery and Production,* pamphlet, American Petroleum Institute, New York, N.Y.)

Refining/Marketing

Finally, the crude oil enters the refinery where it is converted into the thousands of specialized products which modern refining techniques are capable of producing. The majority of the natural gas goes directly to both domestic and commercial fuel consumers via pipeline. The specialty products from the refinery are usually packaged at the site (drums, can, bottles, cases) and moved to the final sales point by air, rail, or highway. Bulk, large volume products (gasoline, jet fuel and fuel oil) are delivered by pipeline to area tank farms and then to retail outlets or final consumers via tank truck.

New Technology

The evolution of new technology has resulted in improved search techniques, the automation of phases of the development and production process, and significant improvements in production methods and equipment.

Several methods have been developed for improving oil recovery from existing reservoirs. One method, pressure maintenance, involves pumping gas or water into the reservoir as oil is produced. This, in effect, replaces the produced oil with injected fluid in an attempt to maintain the reservoir pressure and, hence, stabilize the rate of oil flow resulting in the recovery of more oil over the life of the reservoir.

When fluids are injected into a reservoir that has been depleted by primary recovery methods, the process is termed secondary recovery (or tertiary if the reservior has reached the end of its economic life by secondary recovery). The most important form of secondary recovery is water flooding. In operation, water is pumped through injection wells into the oil reservoir, spreads out from the injection wells and moves towards the oil wells, driving reservoir oil ahead of it. There are other less common method of secondary recovery, including gas cycling or recycling and repressuring by gas injection and insitu combustion. All these processes involve the injection of energy into a reservoir through the use of fluid under pressure.

Mention should be made of well stimulation methoas for improving oil recovery from a particular well. The three most useful processes are fracturing, acidizing and chemical treatment. Fracturing is a technique whereby fluid under tremendous pressure is pumped into a well to open native fractures in the producing formation to increase the flow of oil into the wells. Acidizing produces the same result by the acidic action of the reservoir rock. Chemical treatments involve pumping such chemicals into a well that reduce the surface tension of water and release oil that is trapped behind the surface tension of water.

The dilemma faced by those who are researching other methods of secondary recovery is this: to drive oil out of the poses of a rock, an agent is needed with characteristics that are akin to oil itself. The best agents would be petroleum products. However, injecting petroleum products into a reservoir to improve recovery is economically impractical and self-defeating. Waterflooding will most likely remain the most useful secondary recovery process. In general, waterflooding on a reservoir basis enables the recovery of about as much oil as was recovered by primary recovery, in other words, it doubles the amount of oil produced.

Concerning transportation of hydrocarbons, recent technological developments have resulted in decreasing cost levels. Of particular significance has been the installation of highly automated, large diameter, thin walled (high strength steel) pipeline systems, as well as better protective coatings and insulation.

Technological advances in the refining phase of petroleum production have mainly come about through an increase in the use of computers. Complementing the increasing trend toward automation, recent advances in the technology of petroleum refining have resulted in increased production and improved quality control.

RESOURCE BASE

Oil and gas reserves are located in many areas of the United States, but, as indicated in the diagrams to follow, the largest reserves are found in the mid-continent and Gulf Coast regions.

Figure II-5

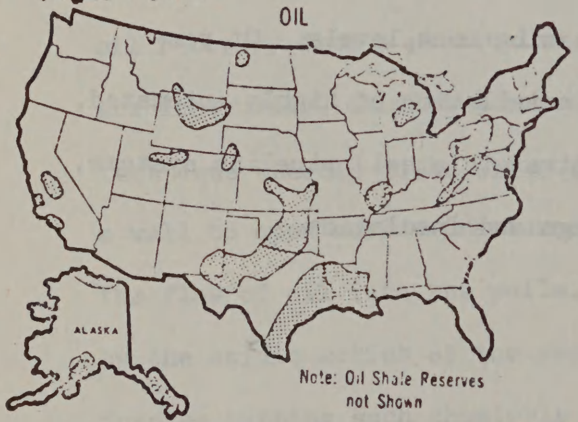
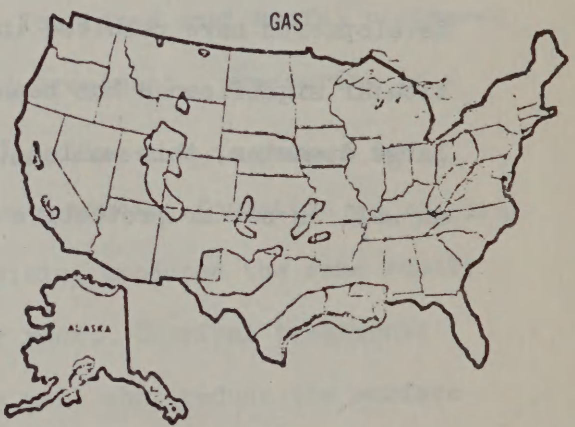


Figure II-6



Source: Federal Power Commission, 1971; the 1970 National Power Survey, Part I, p. 1-4-6.

The following table shows the Geological Survey's latest calculations of proved onshore oil and gas reserves. The table also presents the Survey's estimate of recoverable resources. Offshore reserves are not included in these figures.

Table II-I

U. S. Onshore Oil and Gas Reserves and Resources (Oil 1/ in billions of barrels; gas in trillions of cubic feet)

	Proved Reserves		Recoverable Resources 2/	
	Oil	Gas	Oil	Gas
Public lands	3.0	14.0	250.0	1,153.0
Non-public lands	38.3	237.6	16.0	61.0
Total	41.3	251.6	266.0	1,214.0

1/ Includes natural gas liquids.

2/ Does not include proved reserves.

Alaskan Oil and Gas Reserves

The Prudhoe Bay field currently is estimated to contain 24 billion barrels of oil-in-place. At an estimated recovery rate of 40 percent, the current proved recoverable reserves of the field are 9.6 billion barrels of crude oil. 1/ These reserves alone make the Prudhoe Bay field the largest ever discovered on the North American continent. 2/ Nevertheless, the 9.6 billion barrel estimate may be a conservative indication of the crude oil potential of the field and the Arctic Slope province.

The current reserve estimate for the Prudhoe Bay field is for unextended pools and assumes primary recovery only. With further development drilling and application of secondary recovery techniques, it is likely that at least 20 billion barrels of crude oil will eventually be recovered from the Prudhoe Bay field. This would make it the fifth largest oil field ever discovered in the world. 3/

1/ American Gas Association, American Petroleum Institute, and Canadian Petroleum Institute, Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada and United States Productive Capacity as of December 31, 1970 (May 1971), p. 27.

2/ Michel T. Halbouty, A. A. Meyerhoff, R. E. King, R. D. Dott, Sr., H. D. Klemme, and Theodore Shabad, "World's Giant Oil and Gas Fields, Geologic Factors Affecting Their Formation and Basin Classification", in Michel T. Halbouty, ed., Geology of Giant Petroleum Fields, Memoir 14, American Association of Petroleum Geologists (November 1970).

3/ Halbouty, et. al.

The Prudhoe Bay field has large reserves of natural gas dissolved in or associated with its crude oil reserves. Recoverable gas reserves in the field were estimated to be 26 trillion cubic feet as of the end of 1970. 1/ An average of 750 cubic feet of dissolved gas per barrel 2/ for the proved oil reserves of 9.6 billion barrels would indicate reserves of approximately 7 trillion cubic feet of dissolved gas and 19 trillion cubic feet of associated gas. These reserves, which, like the crude oil reserves of the Prudhoe Bay field, are subject to extension and revision, constituted 8.9 percent of recoverable U. S. natural gas reserves at the end of 1970. 3/ They also make the Prudhoe Bay field the 13th largest gas field ever discovered in the world. 4/

The estimated reserves of the Prudhoe Bay field do not exhaust the oil and gas potential of the Arctic Slope province in Alaska. The

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1/ Reserves of Crude Oil . . . p. 170.

2/ Suggested by the data given in Bureau of Natural Gas, Federal Power Commission, National Gas Supply and Demand: 1971-1990, pp. 98-99.

3/ Reserves of Crude Oil . . . p. 124.

4/ National Gas Supply and Demand: 1971-1990, p. 74.

Prudhoe Bay field is located in the Colville Basin. Geologically, this basin is classified as an intermediate crustal type (i.e., its underlying crust is intermediate to that beneath continents and that beneath oceans), the basin itself being extracontinental (located on the margin of a continent) and sloping downward into a small ocean basin. Extracontinental, downward warping basins are among the richest sources of oil and gas in the world. Examples of such basins include the Arabian platform and Iranian basin (Persian Gulf), the East Texas basin, and the Tampico embayment (Mexico). Over half of the 119 known oil fields with at least one billion barrels of recoverable reserves are found in the 10 known basins of this type. 1/

The ultimate potential of the onshore area in the Arctic Slope province is uncertain. The platform along the Arctic Coast gives considerable geologic indications of being very favorable for both oil and gas. 2/ Comparison with the history of similar basins indicates a high probability of further discoveries of varying size. Professional estimates of ultimate recovery for

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1/ Halbouty, et.al.

2/ George Gryc "Summary of Potential Petroleum Resources of Region 1 (Alaska and Hawaii) - Alaska", and W. P. Brosge and I. L. Tailleur, "The Northern Alaska Petroleum Province", in Ira. H. Cram, ed., Future Petroleum Provinces of the United States - Their Geology and Potential, Volume 1, Memoir 15, American Association of Petroleum Geologists (1971).

the province range from 30 to 50 billion barrels. 1/, 2/ Recall, here, that the Prudhoe Bay field alone is likely to supply 20 billion barrels of crude oil. Considerably higher estimates than these have been made 3/, but the geologic evidence for them is lacking.

Similarly, the natural gas prospects of the North Slope are not limited to the Prudhoe Bay field. Several gas fields were discovered in the 1940's and 1950's on NPR-4, Naval Petroleum Reserve No. 4 (NPR-4), the largest of which was the Gubik field with 300 billion cubic feet of reserves. Geologic investigations of other parts of the North Slope have indicated a favorable potential for future gas discoveries within them as well. 4/

1/ Ira H. Cram, "Future Petroleum Provinces of the United States-Their Geology and Potential: Summary" in Cram, ed., Future Petroleum Provinces. . ., p. 24.

2/ Sam H. Schurr and Paul L. T. Homan, Middle Eastern Oil and the Western World: Prospects and Problems (New York; American Elsevier, 1971), pp. 86-87. Personal communications with Richard Meyer, Office of Oil and Gas, George Gryce, U. S. Geological Survey, U. S. Department of the Interior.

3/ Governor Egan of Alaska was quoted in The Oil Daily July 7, 1971) p. 3, with an estimate of 150 to 300 billion barrels.

4/ See "The Northern Alaska Petroleum Province."

ECONOMIC CONSIDERATIONS

Prices and Costs 1/, 2/, 3/

An overview of the major factors affecting oil and gas cost-price relationships is amply provided in the National Petroleum Council report entitled "Factors Affecting U. S. Exploration, Development, and Production, 1946-1965." Highlights of that presentation include the following: (1) Federal and State policies with respect to abatement of environmental pollution, leasing of Federal and State lands, taxes, and production, and unitization of properties; (2) the changing behavior or price relative to cost factors such as wage rates, and payments for oil field materials and machinery; (3) the decrease in many areas of geological opportunities to make profitable discoveries, especially the older shallow areas, and the shift to the more expensive operating areas of Alaska, and deep inland areas; (4) the changing structure of the industry which is evident in the decline in small companies and individuals and increasing concentration of operations among the large integrated companies; and (5) a decreasing proportion of total industry's revenue from oil and gas production spent on domestic exploration and drilling.

1/ Meadows, P; 1970; op.cit; pp. 162-164.

2/ Warner, A. J.; 1970; op.cit.; pp. 123-124.

3/ This discussion also pertains to offshore oil and gas production.

Economic factors governing the level of crude oil prices at the wellhead are established for areas and fields on the basis of oil and/or gas quality and type, market supply-demand relationships, the competitive relation of oil as delivered to refineries compared with oil from other fields, and other factors.

The 1971 average wellhead value of crude oil in the U. S. was $3.39 per barrel, with the value of natural gas averaging 18.2¢ per thousand cubic feet. In 1971 the gross value of revenues from the production of petroleum totaled over $11.7 billion; the gross value of natural gas totaled about $4 billion.

Because of the general industry attitude concerning the confidentially of cost data, coupled with the physical properties of oil, the environment in which it is found, and the manner in which it is produced, projection of the cost for finding and producing oil is subject to considerable uncertainty. Further complicating the determination of oil and gas costs is the association of oil and gas operations. Industry cost data which is available includes the Joint Association Survey of costs incurred in drilling and equipping wells and other yearly costs of finding, developing, and producing of oil and gas in the continental United States excluding offshore in the Gulf of Mexico and onshore South Louisiana is about $1.84/barrel. 1/

Industry Structure 2/, 3/

In the United States all phases of the development and utilization of petroleum and natural gas are performed by private companies, both large and small. The primary operations performed by these corporations include, 1) the search for and production of petroleum, 2) the transportation of petroleum from producing fields to refineries and distributors, 3) the refining of crude oil, and 4) the distribution of petroleum to consumers.

Firms in the petroleum industry exhibit varying degrees of vertical integration, as they perform from a single to all of the mentioned phases. Often subsidiary companies are formed to undertake supporting functions.

1/ U.S.D.I., Bureau of Land Management, The Role of Petroleum and Natural Gas from the Outer Continental Shelf in the National Supply of Petroleum and Natural Gas, Technical Bulletin No. 5, 1970, p.208.

2/ Warner, A., 1970, op.cit., pp. 113-114.

3/ Meadows, P., 1970, op.cit., pp. 149-150.

Major companies operate throughout the United States, but predominate in areas requiring large investments for drilling and producing operations. Such areas include west Texas and Alaska. Petroleum located in mature producing areas is frequently produced by small independents and individuals. Recently many majors and large independents have expanded their operations into other energy resource fields, as well as petrochemical manufactures and other business areas.

The petrochemical industry is the Nation's third largest industry, following agriculture and public utilities. The natural gas industry is the Nation's sixth largest industry. The petrochemical industry is dominated by 10 majors and the natural gas industry by five majors. Because natural gas occurs in association with petroleum, these commodities are often produced jointly.

Petroleum refineries are situated near producing areas, water transportation facilities, or large market areas. As of 1969, 20 companies controlled 80 percent of the 264 refineries in the United States. In the natural gas industry, 90 percent of interstate sales were made by 10 percent of the producers.

Transportation 1/, 2/

As indicated in Figure II-9, pipelines and water carriers, including tankers and barges, are the primary modes of transport for the crude oil produced in the United States. Pipelines, alone, account for nearly three-fourths of the movement of crude oil and all but a negligible fraction of the distribution of natural gas. So important are pipelines to the natural gas industry that recent increases in the production of natural gas can be attributed largely to major extensions of trunk pipelines. Successes in pipeline technology, including the development of high-quality pipeline steel, welding processes, trenching machines, and efficient compressers have played a significant role in spurring the growth of pipeline systems. Surface tank trucks are used to transport crude oil over short distances, with railroad tank cars reserved for the transport of higher value specialty products. As shown in Figure II-9, trucks in recent years have occupied a larger percentage of the transportation mix for refined product.

1/ Meadows, P; ;970; op.cit., 166-168.

2/ Warner, A. I.; 1970, op.cit.; 125-126.

The domestic cost of transporting crude oil to the refinery may amount to as much as 50 to 60 percent of the delivered cost of oil. Cost for various types of petroleum transportation, including both short and long hauls are compared as follows:

Type of transportation	Mills per ton-mile
Tanker	1.0-2.0
Barge	1.5-6.0
Pipeline	1.7-6.0
Tank Car	20-70
Tank truck	30-50

From the above tabulation, it is evident that transportation costs bear an inverse relationship to the size of the mode of transport. Conversely, lower costs reflect longer hauls and the use of large-capacity carriers. Economics in the transportation of petroleum products have been achieved through increases in the scale of operations, greater use of automation, and better design and quality of materials.

Transportation of Alaskan Oil

Under the Trans-Alaska Pipeline proposal, all of the North Slope oil to be transported by that line would be delivered to and consumed in the West Coast (PAD V) within the first few years after full operation. Deliveries of oil from other fields and by other transportation facilities are too remote and too conjectural for meaningful consideration in current planning.

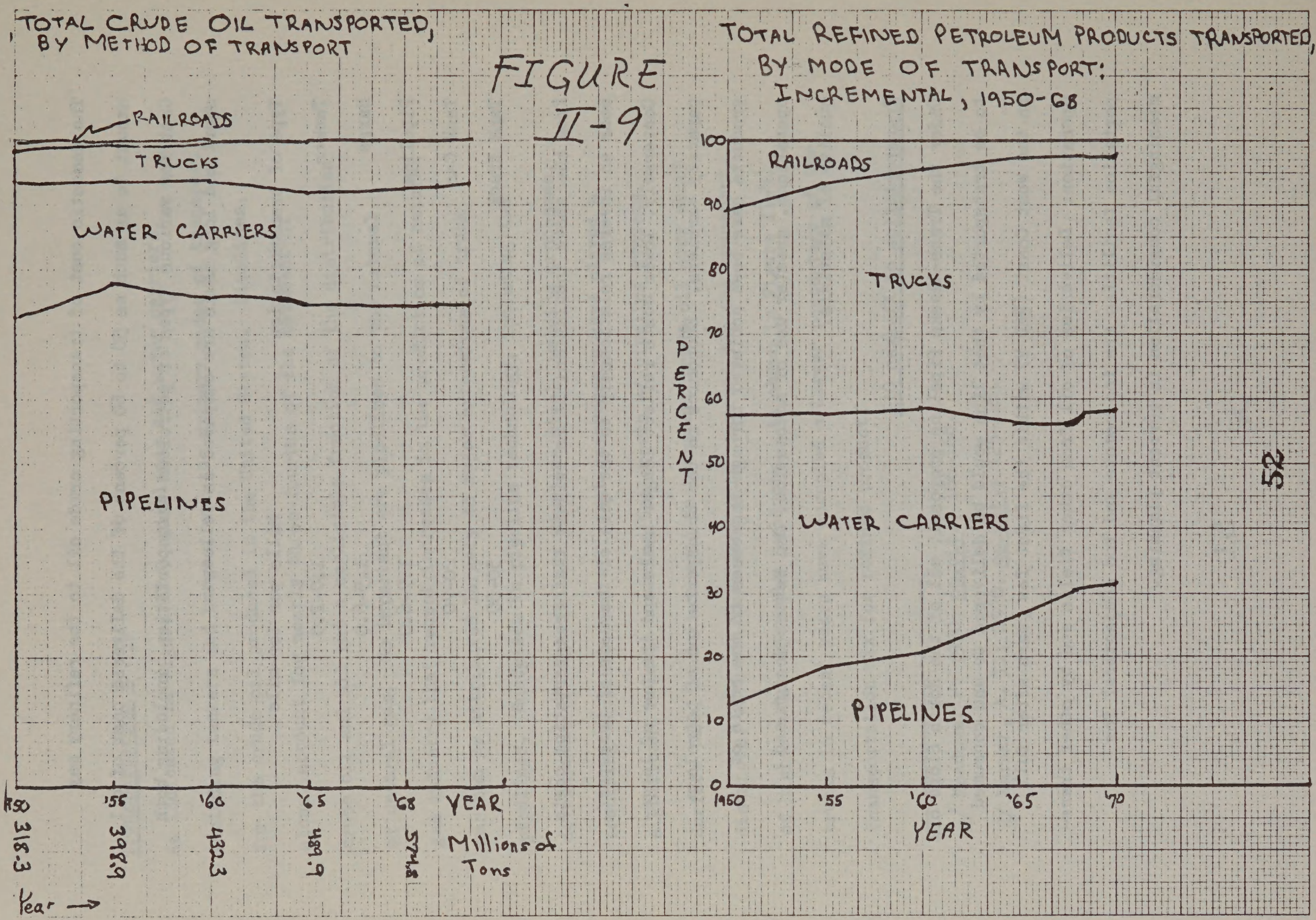
TOTAL CRUDE OIL TRANSPORTED, BY METHOD OF TRANSPORT
RAILROADS
TRUCKS
WATER CARRIERS
PIPELINES
1950
'56
'60
'65
'68
YEAR
318.3
398.9
432.3
489.9
574.8
Millions of Tons
Year →
FIGURE II-9
TOTAL REFINED PETROLEUM PRODUCTS TRANSPORTED, BY MODE OF TRANSPORT: INCREMENTAL, 1950-68
100
90
80
70
60
50
40
30
20
10
0
PERCENT
RAILROADS
TRUCKS
WATER CARRIERS
PIPELINES
1950
'55
'60
'65
'70
YEAR

Figure II-9

Given the large size of the Arctic gas reserves and the projected shortages in other sources of domestic supply, there is high probability that this gas will be developed. Three different consortia have made proposals for gas pipelines up the Mackenzie River Valley to the potential markets. However, many major uncertainties remain; for example, at this time industry experts differ in their opinions about how soon the gas caps in the Prudhoe Bay field can be tapped. Assuming 750 cubic feet of dissolved gas per barrel of oil would be produced, 1.5 billion cubic feet of gas would be produced when oil production reaches a level of 2.0 million barrels per day. Additional gas would be required to meet the full planned pipeline capacity and would have to come from the gas caps. The issue may not be fully resolved until several years after oil production begins, at which time empirical data on the effects on production of associated gas on the production of oil will be available. It is likely that a gas pipeline to the Midwest and lower Canada will ultimately transport gas from both the North Slope and the Mackenzie Delta region.

ENVIRONMENTAL IMPACT

Impact on Air Quality

The impact of additional petroleum production on air quality stems principally from the emission of particulates into the atmosphere; however, some disturbance results from noise and vibrations. These impacts will last as long as operations continue.

Construction and use of access roads and drilling pads introduces dust particles into the air. The removal of vegetation raises maximum surface temperatures and permits increased local wind velocities and evaporation rates. Public use of access roads for hunting, fishing, and off-road vehicle recreation greatly aggravates initial surface disturbance.

Air quality in immediate areas of development will undergo some reduction because of removal of ground cover, vehicle traffic, and occasional equipment failure or blowouts. Vapor venting from storage tanks and vessels, the burning of waste petroleum and chemical products, especially those containing some sulphur compounds, could result in increase of particulates in the atmosphere and objectionable odors.

Noise and vibrations from stationary engines used in drilling and production operations and transporting systems canals disturb the natural environment.

It is highly unlikely that air quality reductions from operations associated with increased petroleum production would significantly alter conditions affecting the growth of flora. The feeding and nesting habits of birds and animals, wilderness qualities and hunting could be altered as a result of noise and vibrations.

Impact on Land Quality

The modification of land form necessary for petroleum production results in varying degrees of environmental impacts on the physical and chemical land characteristics, biological conditions, cultural factors, and ecological relationships.

Depending upon the terrain and local conditions, access to the land is normally from existing road networks, extension of these roads, and expansion of trails. For initial exploratory work, minimum alterations are made in roadway systems. After decisions are made to drill in a given area, an improved road system is required for the transportation of heavy loads. The drilling site must be cleared of vegetation which might present obstacles. Once production has been established, newly constructed roads are normally improved. From these operations environmental impact can result from removal of top soil and surface vegetation to establish right-of-way corridors and location sites, and alteration of drainage patterns and watershed cover.

In the construction of roadways, surface vegetation is removed and drainage patterns are modified. As a result, erosion can occur resulting in changes in landform. Trees, shrubs, grass, and crops may also be subjected to indirect effects by modifications of drainage patterns. Soil erosion and siltation can have both direct and indirect impact upon the normal behavior and activity patterns of wildlife. Small animals and birds may not be significantly affected, although their number in the immediate vicinity of the operations might decrease in proportion to disturbances and lost habitats. The habitat may be altered beyond the life of the producing and transporting operations.

Land use and recreation activities may also be disrupted during drilling, producing and transportation operations. Aesthetic and human interest factors are affected for time-frames beyond the terminations of operations. Scenic views and vistas, wilderness qualities, and physical features in some localities could undergo alterations that could be considered permanent transformations. Population density, employment, and cultural life-styles would change from drilling, production, and transportation levels. The change would be of long-term impact and directly affect access, utility networks, waste disposal and creation of additional corridors.

While the construction of pipeline facilities has the potential for causing unfavorable environmental effects, the employment of good construction techniques can minimize or even eliminate most of these effects. Farming or grazing lands can usually be restored to their original condition after no more than one growing season by the replacement of top soil and the replanting of grass or crops. The aesthetics of wilderness areas can be preserved by using existing rights-of-way or minimizing the width of new rights-of-way, by replacing grass and shrubs on the rights-of-way, and by using such techniques as feathering and screening or deflecting entranceways. Any displacement of wild animals will occur only during the construction. Banks can and should be stabilized to avoid erosion during construction. Access and service roads should be maintained with proper cover, water bars and appropriate slope to avoid soil erosion. Compressor stations and other above ground facilities can be located in unobtrusive sites and planted with appropriate trees and shrubs to enhance their appearance; location, planting and exhaust design can be used to abate excessive noise associated with operation of the compressor stations. Treatment plants can be located and equipped with devices to minimize any adverse effects upon air quality and suitable means, e.g., evaporation ponds or disposal wells, can be found for preserving the water quality of the surrounding area.

Perhaps the greatest adverse environmental impact from oil and gas operations results from oil, chemicals, brine, or waste material pollution. This pollution can result from spills, leaks, blowouts, human errors, or equipment failure. Although care is exercised to prevent land pollution, there are no fail-safe methods to completely protect the environment.

Land pollution, primarily from salt water and accidental oil spills, can result in soil sterilization that could be of long-term nature and affect not only the topsoil but underground water quality. Native vegetation and crops can be adversely affected for short or long-term duration depending upon the volume and toxicity of the pollutant, resistance of the flora, and the techniques and technology employed. Alterations of the flora in turn affect the habitat of birds and animals. Depending upon the degree of pollution, land uses such as agriculture, grazing, forestry, and wilderness can be altered for varying time-frames. In some cases large pollutant concentration could be sufficient to kill vegetation, trees, or crops and disrupt wilderness areas for long-terms. Recreation in areas subjected to large pollutant concentrations can also be altered for long time frames.

Depending upon local conditions, aesthetics such as scenic views and vistas, wilderness qualities, unique ecosystems, or historical sites and objects may be altered. The degree of alterations would be dependent upon the degree of pollutant introduction and local conditions. Disruption of ecological relationships such as food chains, salinization of soil and water resources, could result from pollutant contamination. The degree of contamination has a bearing upon the duration of the environmental impact.

In exploring and pipelining, any spills that occur normally would be small. Major spills could occur in drilling, production, and in the movement of petroleum liquids by marine transportation. The Federal Water Quality Administration (EPA) estimates that 10,000 oil spills occur a year of which 2,500 are ground spills. 1/ Most ground spills cause little ground pollution. According to the 1970 report of the Office of Pipeline Safety (Department of Transportation) on spill incidents, there was a total of 347 liquid pipeline accidents. In those accidents, spills averaged approximately 1,780 barrels of crude oil. Principal cuase of over 50 percent of accidents was corrosion. Many onshore pipelines are old, dating back to 1920's before techniques for protection against corrosion became widely used. Continued accidents can be expected from these

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1/ National Petroleum Council, Environmental Conservation, op.cit. p. 146.

lines. With the development and expanded use of cathodic protection of pipelines, fewer accidents in new lines would be expected, but accidents from old lines will continue to be of concern.

Impact on Water Quality

The construction of roads for access into prospective petroleum producing areas could affect water quality by disturbing drainage patterns and causing erosion. The dredging of canals could result in increased turbidity and resuspension of bottom sediments as well as salt water intrusion.

Turbidity is considered to be of short-term duration but may affect local flora and fauna. Siltation of water reservoirs and estuaries has long-range environmental impacts in that the shape and size of the water basin is altered. This can have an adverse impact on flora, recreation activities, aesthetic qualities and perhaps disturb ecological food chain relationships.

One of the major environmental risks of petroleum production operations is the entry of foreign substances such as oil, chemicals, brine, and waste materials into the water cycle. Spills or leaks releasing these substances result from human error, corrosion of pipelines and vessels, ruptures or mechanical failures, burning pits, open ditches and blowouts.

Large amounts of salt water may accompany oil production as oil fields age. Such water can create pollution problems from producing wells on land or freshwater-covered areas. According to a study of the Interstate Oil Compact Commission (IOCC), up to 25 million barrels of salt water are produced daily from the Nation's oil wells. Proper disposal of produced brines has been and continues to be of major concern to producing operators, and regulatory agencies. Subsurface disposal is strictly regulated by some state conservation agencies and disposal of salt water is not permitted in freshwater streams. 1/

The introduction of oil or brine into the water cycle can adversely affect vegetation and aquatic plants, birds, land animals, and fish. Sheltered lagoons and estuaries impose natural dispersal restrictions on oil spills causing the oil to remain trapped or concentrated in such areas for long periods. Major reductions in water quality that significantly disrupt the food chains in bays, lagoons, and estuaries could have long-term environmental effects.

1/ National Petroleum Council, Environmental Conservation, The Oil and Gas Industries, Vol. II, 1972, p. 147.

SPECIAL CONSIDERATIONS

Nuclear stimulation, an experimental method of fracturing low permeability gas reservoirs otherwise incapable of sustaining commercial production, has potential to add materially to U. S. recoverable gas reserves. The Atomic Energy Commission is conducting research and development of nuclear explosives and techniques for utilizing the effects of multiple nuclear explosives to recover natural gas locked in tight geological formations. Such gas cannot now be economically produced by conventional methods. Most reserves amenable to nuclear stimulation lie in thick, deep reservoirs of very low natural permeability located in the Rocky Mountain area.

Project Gasbuggy, a cooperative effort of the AEC, the Department of the Interior, and El Paso Natural Gas Company, involved detonation of a 29 kiloton nuclear explosive in the Pictured Cliffs formation, a gas bearing rock strata near Farmington, New Mexico. The explosive, set off at a depth of approximately 4,200 feet, on December 10, 1967, created an underground column or chimney containing about 2.3 million cubic feet of crushed rock. There was no unplanned release of radioactivity to the environment. By November 1969 nearly 300 million cubic feet of gas was extracted from the chimney through intermittent production testing of the well.

Projects Gasbuggy and Rulison were basic experiments each involving the detonation of a single nuclear explosive but at different depths and in different gas formations. Both of these projects clearly demonstrated that recovery of natural gas by nuclear explosion stimulation is technically feasible and economically promising. The current development phase involves techniques for using multiple explosives in a single wellbore. Gas formations amenable to nuclear explosion stimulation are thicker than can be effectively and feasibly stimulated by a single explosion. The Rio Blanco Project, part of this phase, involved simultaneous detonation of three 30-Kiloton nuclear devices more than a mile underground on May 17, 1973. The stimulated well near Meeker, Colorado is expected to produce 17.5 billion cubic feet of natural gas from sandstone formations. The gas should fill the chimney created by the explosions, from where it can be piped to the surface.

The Atomic Energy Commission has reported on the possible scope of nuclear stimulation, and has provided an economic assessment of the technical programs needed to achieve commercially viable application of nuclear stimulation of natural gas wells. Current emphasis in the Plowshore program is to develop technology. A research and development period of approximately 5 years is required, which includes the design and testing of explosives and execution and evaluation of pilot tests in each basin. The Rio Blanco Gas Stimulation Project impact statement discusses a three - phase demonstration program for the Rio Blanco Unit which is being considered by the industrial sponsor, but for which there is as yet no Government committment. Assuming success during experimental testing, commercial development could begin by the late 1970's.

A scenario developed by the Lawrence Livermore Laboratory (LLL)1/ assumes technical capability and public acceptance of drilling, necessary field construction, and explosive firing of 80 wells (290 explosives) per year by 1980. This could result in the production of about 600 Bcf of natural gas per year by that time. Favorable conditions might allow a development program of 100 wells (370 explosives) per year beginning in 1981. Such a schedule could yield 1.50 Tcf per year (4.35 billion cf/day) by 1985. This corresponds to an energy production of 4.35 trillion Btu's/day.

ENVIRONMENTAL IMPACT

Environmental effects of nuclear stimulations to increase natural gas production from tight reservoirs are related to radioactivity and seismic disturbance, both of which concern the surface or subsurface, leaving atmospheric contamination or disturbance unlikely. The depth of the gas formations of interest throughout the Rocky Mountain area is such that the probability of releasing any appreciable amounts of radioactivity to the atmosphere at detonation time is considered negligible. Most radioactivity produced by the explosives will remain underground trapped in the resolidified rock near the bottom of the chimney or attached to the rock surfaces in the chimney. Project design would take into account mobile waters and assure that chimneys remain isolated from them. The formations of interest for nuclear - explosive stimulations are generally at depths of 5,000 to 10,000 feet or deeper, have low permeability, and would not be

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1/Rubin, B., Schwartz, L., and Montan, D., "An Analysis of Gas stimulation Using Nuclear Explosives," Rept. UCRL-51226, May 15, 1972.

expected to contain mobile water. Significant vertical communication with shallow water-bearing formations through existing or created faults or fractures must be avoided. Water produced with the gas from nuclear-explosive stimulated wells will contain very low levels of tritium. Control methods to dispose of this contaminant are being developed.

The chemical composition of the gas itself in each stimulated well is assumed to be similar to that measured in the first experiments. The initially large carbon dioxide concentration in the chimney either would be reduced by dilution with pipeline gas or would be removed by standard gas field practices. After production of a few chimney volumes the carbon dioxide would be depleted and the gas composition would be essentially the same as that from conventional wells. Gas production from the wells would be delayed until short-lived radionuclides decayed. Technical information from subsequent experiments will aid in defining the time for initiation of production.

The remaining gaseous isotopes--tritium and krypton-85-produced with the first few chimney volumes of gas, are calculated to provide less than one millirem per year of exposure to the general population if the gas were used as a part of the total gas supply to a large city. No insurmountable problem is anticipated in meeting future regulations or standards developed for sale of the gas.

The potential environmental impacts resulting from nuclear stimulation of a single well or in a small geographic area have been evaluated in the environmental statements prepared for the Rio Blanco[1/] [2/] and proposed Wagon Wheel[3/] projects. Extrapolation of the impact to a full commercial development relates primarily to the frequency and size of explosives and to changes in local environment as the areas of development expand.

The hypothetical plan developed by the AEC's Lawrence Livermore Laboratory describes drilling and firing 100 wells per year (for possibly 50 to 60 years). On the average this would involve approximately 370 explosives per year, usually 3 or 4 explosives in each well. The AEC estimates only three or four detonation days per year should suffice for the 30 to 40 wells to be completed for each field area. The size of the explosive required to stimulate very thick geologic formations and the actual seismic effect of such explosions are still being evaluated.

In extrapolating the projected or observed impact of test projects, consideration must be given to the total environment of the basin. The site for the Rio Blanco experiment, for example, is relatively isolated. There are thought to be no surface or subsurface structures or operations in the zone of substantial damage. The fact that this will not invariably be true is an important consideration when planning commercial development.

[1/] Environmental Statement--Rio Blanco Gas Stimulations Project, U. S. Atomic Energy Commission, Washington, D.C., WASH-1519 (April 1972).

[2/] Environmental Statement Addendum, Rio Blanco Gas Stimulation Project, WASH-1519 (March 1973).

[3/] Environmental Statement--Wagon Wheel Gas Stimulation Project, U. S. Atomic Energy Commission, Washington, D. C., WASH-1524 (April 1972).

By its nature, nuclear stimulation has a dramatically disruptive effect on the nearby natural-gas host rock. The fracture zone should extend 300 to 400 feet from the center of the explosion. Also the compression wave moving out from the explosion can cause spall near a free surface (ground level) or increased faulting or fracturing in areas where there is a large natural directional stress concentration. This would lead to concern if other valuable mineral resources exist in the area. However, the areas being considered for nuclear stimulation are relatively seismically inactive and would not appear to have large natural stresses required for such structural failures. The development of nuclear stimulation of natural gas reservoirs may be accompanied by some possible damage to existing structures due to ground motion. Damages would have to be prevented (as by bracing), repaired, or compensation rendered to owners. Ground motion is predictable and utmost care would be used to minimize this effect.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

To directly substitute for the proposed sale, onshore oil production would have to increase by 270,000-443,000 barrels a day and onshore gas production by 0.34-0.52 billion cubic feet a day. The mix of oil and gas that would provide the same Btu value as the expected MAFLA production ranges from all oil, 331,000-536,000 barrels a day, to all gas, 1.86-3.01 billion cf a day. These increases in production from onshore sources, other than the Naval Petroleum Reserves or the Alaska North Slope, would probably have to originate in areas not now deemed economically viable. It is likely that economic incentives such as a rise in prices would be required to stimulate exploration and development. Current low exploratory and discovery rates, high production levels and continued decline in reserves, must be reversed before production can be maintained at its current level, let alone be increased.

Naval Petroleum Reserve No. 1, at Elk Hills, California, has a current producing rate of less than 4,000 barrels a day. With Congressional approval this rate could be increased to 160,000 barrels a day using existing facilities and to 267,000 to 350,000 barrels a day with additional investments. Because this level of production is less than that expected from the MAFLA sale, NPR No. 1 could not, by itself, replace the proposed sale.

Production from the Alaska North Slope oil field would be sufficient to substitute for the proposed sale. Under the Trans-Alaska Pipeline proposal, however, all of the North Slope oil would be delivered to and consumed in PAD V (West Coast) within the first few years of pipeline operation. Since 99 percent of the oil produced from the proposed sale would be consumed in PAD Districts I-IV, oil from the North Slope cannot be considered an alternative to the sale. In addition, legal and environmental difficulties may delay development of the North Slope.

B. Deregulation of the Wellhead Price of Natural Gas

BACKGROUND

The sale of natural gas for resale in interstate commerce is currently under Federal Power Commission (FPC) jurisdiction. In 1954, the Supreme Court ruled that independent producers of natural gas, whose sale of gas goes into interstate commerce, were not exempted from regulations under the Natural Gas Act.

Although in the past few years, the FPC has modified its pricing policies to be more responsive to the gas supply situation, including the recent order extending the sales period from 60 to 180 days for temporary emergency gas sales without FPC approval, on April 10, 1973, the FPC Chairman urged Congressional action to amend the Natural Gas Act to decontrol the price of new gas supplies. The President, in his energy message to Congress April 18, 1973, proposed such action stating:

> "For more than a decade the prices of natural gas supplied to pipelines under this extended regulation have been kept artificially low. As a result, demand has been artificially stimulated, but the exploration and development required to provide new supplies to satisfy this increasing demand have been allowed to wither. This form of government regulation has contributed heavily to the shortages we have experienced, and to the greater scarcity we now anticipate.

As a result of its low regulated price, more than 50 percent of our natural gas is consumed by industrial users and utilities, many of which might otherwise be using coal or oil. While homeowners are being forced to turn away from natural gas and toward more expensive fuels, unnecessarily large quantities of natural gas are being used by industry.

Furthermore, because prices within producing States are often higher than the interstate prices established by the Federal Power Commission, most newly discovered and newly produced natural gas does not enter interstate pipelines. Potential consumers in non-producing States thus suffer the worst shortages. While the Federal Power Commission has tried to alleviate these problems, the regulatory framework and attendant judicial constraints inhibit the ability of the Commission to respond adequately.

It is clear that the price paid to producers for natural gas in interstate trade must increase if there is to be the needed incentive for increasing supply and reducing inefficient usage. Some have suggested additional regulation to provide new incentives, but we have already seen the pitfalls in this approach. We must regulate less, not more. At the same time, we cannot remove the price of gas currently in production and generating windfall profits.

To resolve this issue, I am proposing that gas from new wells, gas newly-dedicated to interstate markets, and the continuing production of natural gas from expired contracts should no longer be subject to price regulation at the wellhead. Enactment of this legislation should stimulate new exploration and development. At the same time, because increased prices on new unregulated gas would be averaged in with the prices for gas that is still regulated, the consumer should be protected against precipitous cost increases.

To add further consumer protection against unjustified price increases, I propose that the Secretary of the Interior be given authority to impose a ceiling on the price of new natural gas when circumstances warrant. Before exercising this power, the Secretary would consider the cost of alternative domestic fuels, taking into account the superiority of natural gas from an environmental standpoint. He would also consider the importance of encouraging production and more efficient use of natural gas."

Concurrent with the President's Energy Message, the Department of the Interior submitted to Congress proposed legislation to amend the Natural Gas Act. Until such legislation is passed by Congress, however, the wellhead price of new gas will continue to be regulated by the Federal Power Commission.

RESOURCE BASE

The Potential Gas Committee has estimated the remaining undiscovered reserves of gas in the United States as 1,146 tcf as of December 31, 1972 and has divided these reserves by region and by degree of uncertainty. This amount is approximately 4.9 times the 1972 proven reserves of the lower forty-eight states, indicating that substantial additional reserves may be developed if economic incentives improve.

ECONOMIC CONSIDERATIONS

Deregulation of the price of new gas is a policy option that if implemented, should stimulate the economic incentive for the discovery of new supplies and reduce inefficient use of the fuel. In order to determine the effectiveness of such policy options on these objectives, it is necessary to estimate the extent of producers' and consumers' responses to increasing prices.

When prices go up, producers find greater opportunity for profit in developing resources which might otherwise seem too risky or uneconomical to develop. On the other hand, consumers are less willing to pay higher prices and may curtail some uses of the fuel, tending to bring supply and demand into balance. While supply and demand elasticities have been the subject of much research, very little is known of the quantitative relationships.

Demand Elasticity

Six econometric studies were reviewed by Professor Draper in Regulation of the Natural Gas Producing Industry on price demand elasticity: 1/

1. Vermetten and Plantinga (1953). This study deals principally with the cross elasticity of gas and other energy sources in eleven industries aggregated by states. The elasticities ranged from -0.33 to -4.99 based on evaluation of 1947 data. (A -0.3 demand elasticity can be interpreted that a 10% increase in price would cause a 3% reduction in quantity demanded).

1/ Brown, Keith C., Regulation of the Natural Gas Producing Industry, pp. 49-55.

2. Wein (1961). This study used multiple regression analysis to estimate twelve equations involving factors thought to determine exploration, and residential, commercial and industrial demand. Cross section analysis was used for the year 1961 with data aggregated by state. The results indicated that elasticity of industrial consumption was about three times as large as the elasticity of residential and commercial consumption with respect to price; indicating that industrial users of gas respond more rapidly to higher gas prices by demanding less or converting to another fuel, than residential and commercial users. Industrial demand was highly elastic, -2.5, with combined residential and commercial demand having an elasticity of -0.8. Professor Draper intimates that one of the more important problems with the study is the choice of independent variables used to determine demand and exploration.

3. Villanueva (1964). This study attempts to estimate the variables affecting gas demand of the major sectors of the consumer markets and to estimate the effects of gas rates on the distribution of the fuel between consumer groups. Multiple regression analyses were performed with independent variables including prices of natural gas and competitive fuels, income, temperature, housing starts and measures of consuming-industry activity for the period 1950-60. Estimated price elasticities of -1.83, -1.39 and -0.51 resulted for regional gas demand of residential-commercial consumers in three of the five regions analyzed. Price elasticities of regional demand by industrial consumers ranged from -1.34 to -1.64 for three of the five regions. One of the major criticisms of this study is that data was aggregated to such an extent that an insufficient number of observations of the variables resulted in difficult interpretation of the statistically significant variables.

4. Balestra (1967). This study attempted to develop a dynamic demand equation for natural gas in the residential and commercial sectors of the economy. A short-run demand function relating demand to

availability of gas, the stock of gas-using appliances, the real price of gas and the real per capita income using 1950-62 data resulted in elasticities ranging from -0.00002 to -7.75. The conclusions from the short-run analyses were that the total demand for fuels is fairly inelastic in the short-run; substitution of fuels must be small in the short-run given the consumers' stock of major appliances; and the upward trend in elasticity suggests that competition from alternative sources of energy may become stronger in future years. Draper summarizes the limitations of this study as "...difficult to interpret the results when so many analyses were performed, their results are not in agreement, and there is no clear theoretical basis for choosing among the different models."

5. Tummala (1968). Two models were developed in this study to explain the demand for natural gas in the residential, commercial and industrial sectors using annual time series data for the state of Michigan from 1946-1964. One model, the simultaneous equations model, estimated burner tip price elasticities of demand in the residential, commercial and industrial sectors as -0.44, -0.60 and -1.33, respectively. The other model, a distributed-lag

model, produced some results not in accord with economic theory. Major problems were with the level of aggregation of the Michigan data and with the ensuing equations having statistically insignificant coefficients.

6. Gujarati (1970). This study attempted to determine the ratio of electric space-heating customers to total residential customers using price of electricity, price of gas, personal income of the consumer, degree days, and number of housing units of various types. Multiple regression analyses were used for the period 1963-1967 for twenty-seven privately owned utilities. This study is not directly relevant since we are concerned here with the effect of deregulation on the demand for and supply of natural gas to all users, not just the residential customer.

It is apparent from the review of these studies that widespread differences exist in the extent of demand elasticity of natural gas. Each study has its problems and limitations, as pointed out by Draper, making reliance on any particular set of elasticities suspect.

Another problem exists in that demand elasticity is analyzed in terms of end users only. When considering deregulation of wellhead prices in terms of its effect on supply-demand imbalances, supply and demand elasticities at the wellhead are more essential issues. None of the six studies addresses these issues, although wellhead demand is derived from user demand.

In summary, little can be said with assurance except that demand elasticity is negative. If the wellhead price of gas is deregulated, however, and such price increases ten percent, any decrease in demand by pipeline companies in the short-run might be expected to be less than ten percent.

Supply Elasticity

Four recent studies have been made concerning price supply elasticity. Some of the same problems concerning level of aggregation of data, availability of relevant data, serial correlation problems and proper identification of the supply function using significant variables from the data base, are prevalent in these studies as well. Although questions have been raised concerning the accuracy of these studies also, the results have not been as divergent as those concerning demand elasticity.

1. Garrett (1970). 1/ This study, using 1955-69 data, attempts to measure the reserves that would become economically exploitable due to an increase in the wellhead price of gas, not the amount that would be discovered. However, a constant elasticity of supply estimate can be derived of 0.5, indicating that a ten percent increase in wellhead price would increase natural gas supply five percent.

2. Erickson - Spann (1971). 2/ An attempt was made, using 1946-59 data, to account for the problem of joint costs, or the difficulty of separating gas well costs from oil well costs. It was concluded that oil prices have no long range effect on gas supply and may, in the short-run have a negative cross elasticity effect; in other words, an increase in oil price may decrease gas supply for a short period of time, but is not expected to have an effect on gas supply in the long-run. The best estimate of gas supply elasticity was 0.5, with a 0.69 elasticity over the long-run.

1/ Garrett, Ralph, "The Effect of Prices on Future Natural Gas Supplies," mimeographed.

2/ Brown, K. C., Regulation of the Natural Gas Producing Industry, pp. 192-218.

3. Khazzoom (1971). 1/ This model, developed for the Federal Power Commission, does not estimate a constant elasticity of supply value, but an equation based on 1961-68 data, showing gas supply as a function of several variables, one of which is price. Thus, the supply elasticity estimate varies from year to year, but varies under an assumed continuation of regulation.

4. MacAvoy (1971). 2/ Preregulation data in the period 1954-60 was used to empirically estimate a market clearing model, where supply, demand and wellhead prices were hypothetically at a state of equilibrium. The model is then applied to 1961-67 data and the differences between actual reserve additions and wellhead prices, and the market clearing values are compared. These differences are assumed to be the result of lower supply at lower regulated prices. A supply elasticity value of 0.45 was obtained for the long-run.

1/ The Bell Journal of Economics and Management Science, Vol. 2, No. 1, pp. 51-93.

2/ Brown, K. C., Regulation of the Natural Gas Producing Industry, pp. 169-191.

SUPPLY ELASTICITY ESTIMATES

AUTHOR AND DATE	DATA	SUPPLY ELASTICITIES
Garrett (1970)	1955-69	0.5
Erickson-Spann (1971)	1946-59	0.69 0.5 (best judgement)
Khazzoom (1971)	1961-68	No constant estimate
MacAvoy (1971)	1954-60	0.45

Thus, it appears that a 0.5 supply elasticity estimate might be a reasonable consensus of opinion of supply response to price. If the new average wellhead price is 27¢ per Mcf with reserve additions at 9.4 tcf, an increase in price to 40¢ might raise available reserve additions 2.3 tcf to 11.7 tcf. This price amount must be modified by an estimate of demand elasticity. Unfortunately, it is difficult to obtain a consensus on demand elasticity, since demand is established in reference to consumer as opposed to wellhead prices and since there is much variation in the available estimates. Thus, although an additional 2.3 tcf might be available at 40¢ per Mcf, demand elasticities may have some effect on this price.

A report was issued recently by the American Petroleum Institute estimating the impact of alternative deregulation proposals on natural gas prices. The estimates were based on analysis of gas sales contracts in effect on January 1, 1973, varying assumptions as to market price levels in the event of deregulation, and projections of "new" and "old" gas delivery volumes to 1980.

Delivery volumes and prices of "old" gas were projected to 1980 from volumes and prices payable under existing contracts for 2 Bcf or more annually. It was assumed that prices would rise to the estimated market level upon expiration of the contract and whenever contractual provisions would permit. The study estimates that as of January 1, 1974, 62% of the sales volumes under existing contracts would not be subject to escalation to the current market price. This percentage would drop to 48% by January 1, 1980.

With respect to "new" gas sales, it was assumed that new supplies would be committed at the market price and that annual reserve additions would increase from 10 tcf to 19 tcf by 1975 and 27 tcf by 1980. The delivery volumes derived for "old" and "new" gas resulted in fairly stable production through 1976, increasing thereafter by approximately 2% annually.

The report noted that a positive relationship between supply and price was widely recognized, but that no technique as yet been developed for reliably estimating the price elasticity of supply.

Projections of the impacts of deregulation at various market prices are summarized below:

Estimated Average Field Prices, All Sales

	Deregulation of All Sales	Deregulation of New Sales and Expiring Contracts	Deregulation of New Sales Only
	-----------	(cents per Mcf)	-----------
Assuming 55¢ Market Price			
1/1/74	26.80	22.96	22.08
1/1/77	35.84	32.17	30.11
1/1/80	45.66	43.43	39.52
Assuming 65¢ Market Price			
1/1/74	28.12	23.44	22.27
1/1/77	39.41	34.94	32.23
1/1/80	51.45	48.84	43.80
Assuming 75¢ Market Price			
1/1/74	29.45	23.92	22.46
1/1/77	42.97	37.71	34.36
1/1/80	57.25	54.25	48.07

The above estimates compare with the average field price of 20.48¢ for all interstate gas deliveries as of 1/1/73.

The report has aroused considerable controversy, criticisms have been made that the report is misleading and deceptive in that market prices may rise considerably higher than the 75¢ maximum assumed level in the report with greater costs to the consumer.

ENVIRONMENTAL IMPACT

An analysis of the environmental impact of the proposed deregulation of the wellhead price of gas has been prepared by the Department of the Interior in its draft environmental impact statement. As stated in the statement, this alternative would not result directly in any specific action. It would, however, trigger market forces which would result in increased activities impacting on the environment. These activities would center on increased domestic production both onshore and offshore, of natural gas and associated oil. More detailed discussions of the impact of these activities are contained in both the draft statement on the proposed deregulation and elsewhere in this statement.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

Under the Natural Gas Act, the Federal Power Commission has the authority to regulate the wellhead price of natural gas which goes into interstate commerce. It has been argued that the prices established by the FPC have been too low and have, therefore, increased demand while discouraging exploration and development. Studies of the responsiveness of the supply and demand of natural gas to price changes have been done; the results, however, are not conclusive. It is difficult, therefore, to accurately predict the impact of deregulation. The amount of production which could be stimulated by this alternative would probably be equal to or greater than the energy expected from the proposed sale.

3. Coal

TECHNOLOGICAL PROCESSES

Coal is mined in the United States by two primary methods: (1) strip (surface or open pit) mining, and (2) underground mining. The method employed is based mainly on the amount of overburden overlying the coal seam. Other considerations affecting this decision include topography, and surface area requirements for mine wastes and processing equipment.

Coal mining by surface methods can be classified into two major types: (1) contour mining which is employed in hilly or mountainous terrain where the hillside or slope limits the width of the potential area to be mined, and (2) area mining, a technique employed when the coal seams are flat-lying, thereby allowing the coal to be mined in a succession of pits or open cuts.

When coal properties permit mining by area surface techniques, large tonnages may be mined by pits advancing across consolidated mining areas. Large capacity shovels and draglines are used in this situation, to achieve maximum efficiency of large-scale operations.

In contour mining the trend in equipment use has been toward smaller draglines and shovels. Smaller equipment has been used primarily because of the need for mobility. Larger equipment would not enable the operator to recover enough additional tonnage to offset the additional capital costs. In rough terrain where contour mining is normally practiced, haulage from the pit to the loading point or preparation plant is generally performed with highway trucks. Such vehicles are used because of the high cost of haulage road construction and the rapidity with which the mining site changes.

The National Petroleum Council shows the extent of contour versus area mining methods in the Eastern United States in the following table. 1/ In the Western states, area mining is the primary form of surface recovery.

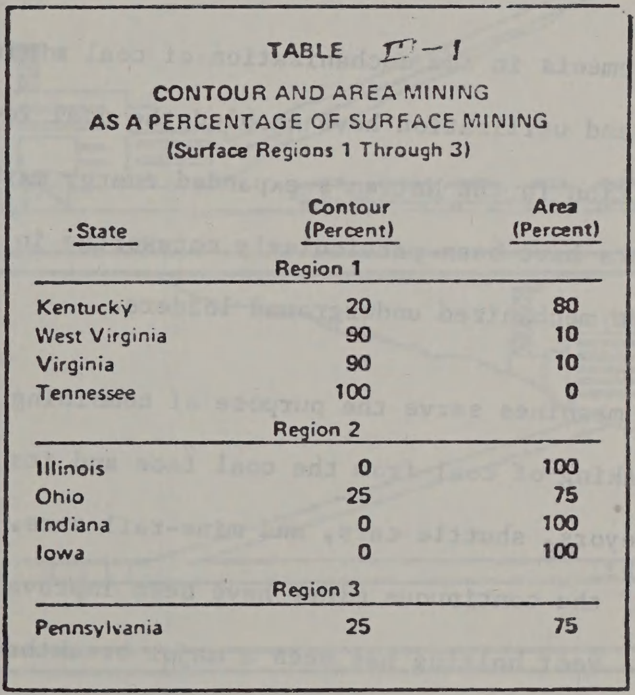

TABLE IV-1

CONTOUR AND AREA MINING
AS A PERCENTAGE OF SURFACE MINING
(Surface Regions 1 Through 3)

State	Contour (Percent)	Area (Percent)
Region 1		
Kentucky	20	80
West Virginia	90	10
Virginia	90	10
Tennessee	100	0
Region 2		
Illinois	0	100
Ohio	25	75
Indiana	0	100
Iowa	0	100
Region 3		
Pennsylvania	25	75

1/ Reproduced from National Petroleum Council (1972) op. cit., p. 159.

Three types of mines are used for underground mining: (1) shaft mines, (2) drift mines, and (3) slope mines. The type of underground mine employed depends primarily on the attitude and thickness of the coal seam, as well as the depth of overburden. Figure III-1 shows the three types of underground mines, as well as a surface mine. 1/ Figure III-3 diagrams the operation of a shaft mine. 2/

Following processing, the coal is transported by rail, water carrier, truck, or pipeline to its purchaser.

Significant advancements in the mechanization of coal mining, and modes of transportation and utilization have enabled the coal industry to hold a substantial position in the Nation's expanded energy market. Technological advancements have been particularly noteworthy in continuous mining machines and mechanized underground loaders.

Continuous mining machines serve the purpose of combining into a single operation the breaking of coal from the coal face and its mechanized loading into conveyors, shuttle cars, and mine-rail cars. Complementing the development of the continuous miner have been improved techniques for roof bolting. Roof bolting has been a major breakthrough, as it has lessened or removed the need for timbering, thereby permitting the

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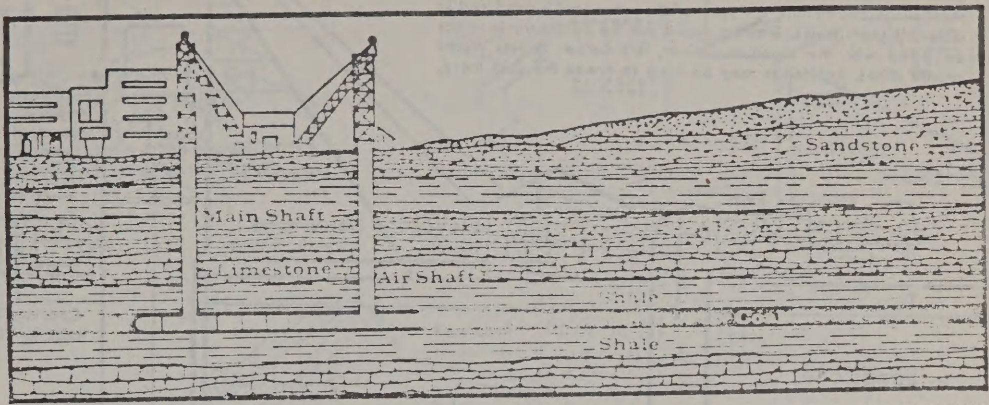
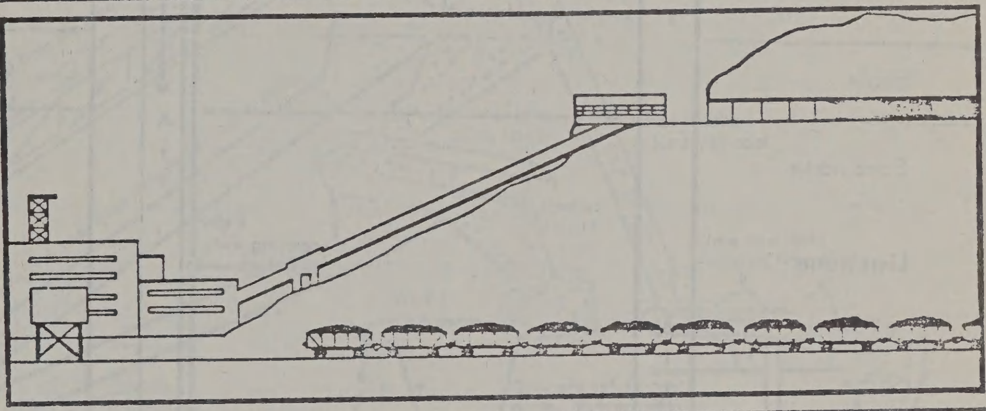
1/ Reproduced from "Bituminous Coal Facts, 1972", National Coal Association, p. 17.

2/ Reproduced from "Coal", A reprint from the World Book Encyclopedia, 1971, p. 569.

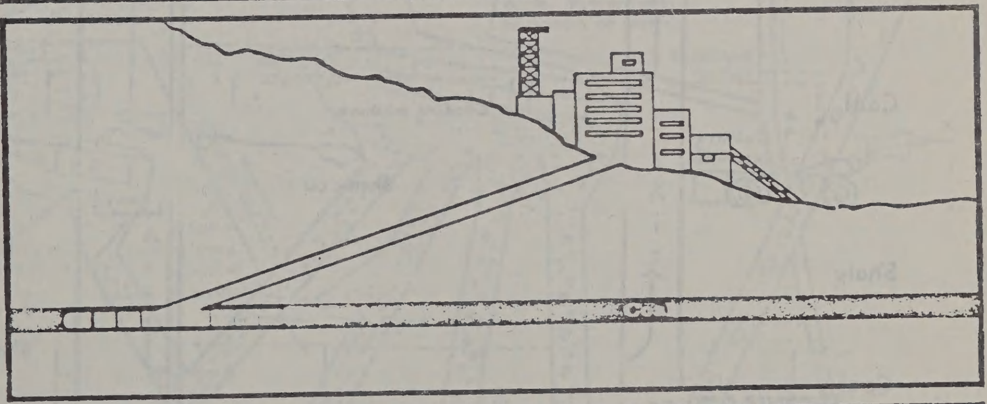
FOUR TYPES OF BITUMINOUS COAL MINES



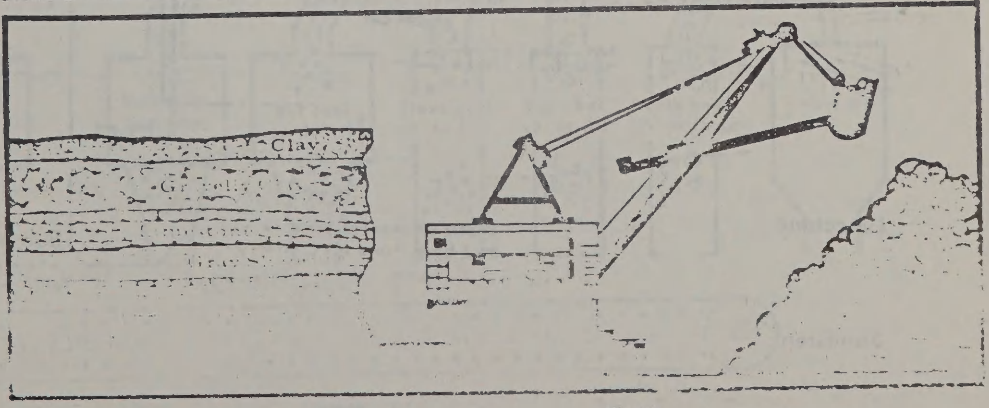
Shaft Mine



Drift Mine



Slope Mine



Surface Mine

Figure III-1

HOW A SHAFT MINE OPERATES

Coal that lies deep below the earth's surface is often reached by shaft mines. Shown here are some of the ways coal is produced in different shaft mines. Blasting would not be necessary in mines equipped with the continuous miner, *left below*. In less mechanized mines, explosives may be used to break the coal loose.

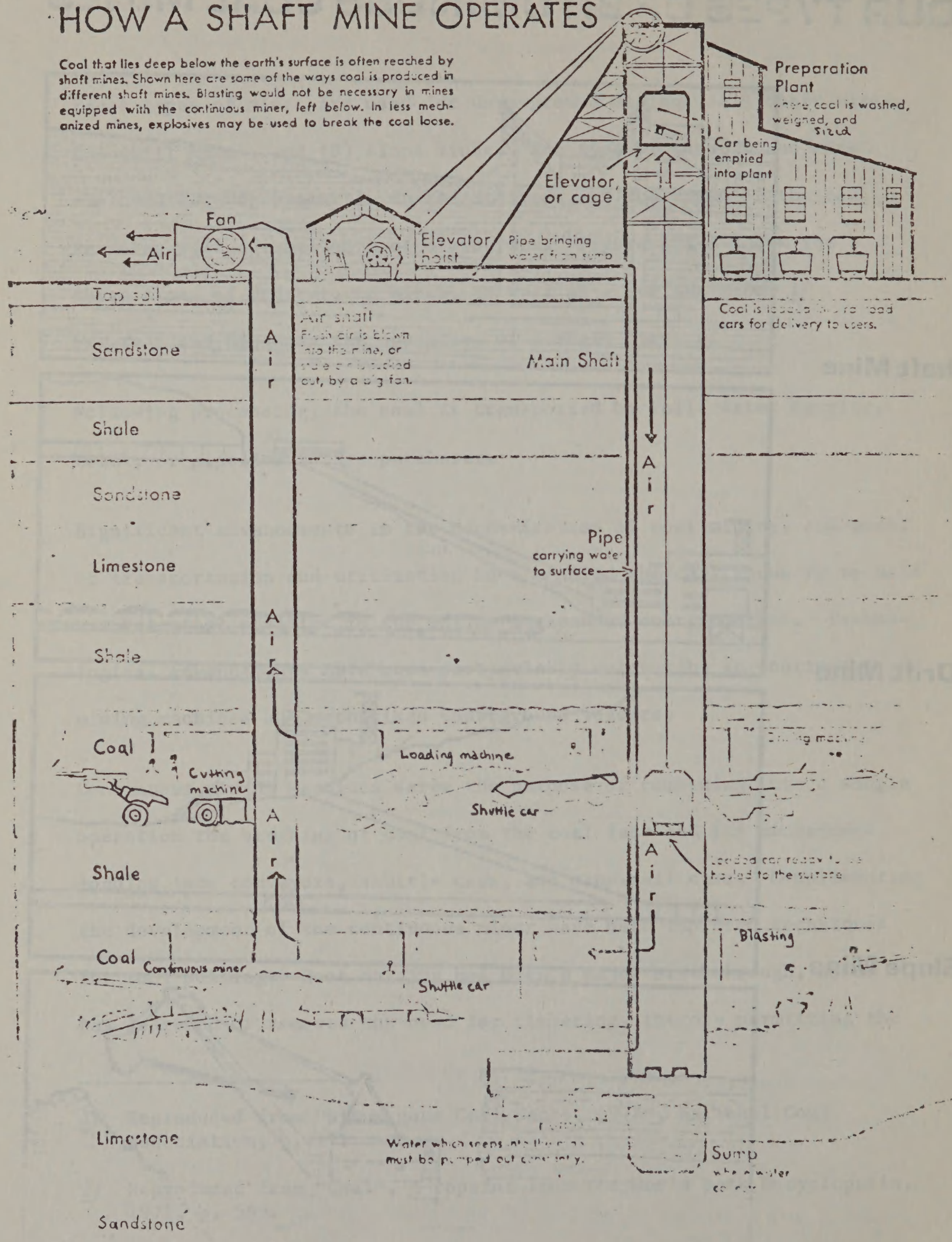
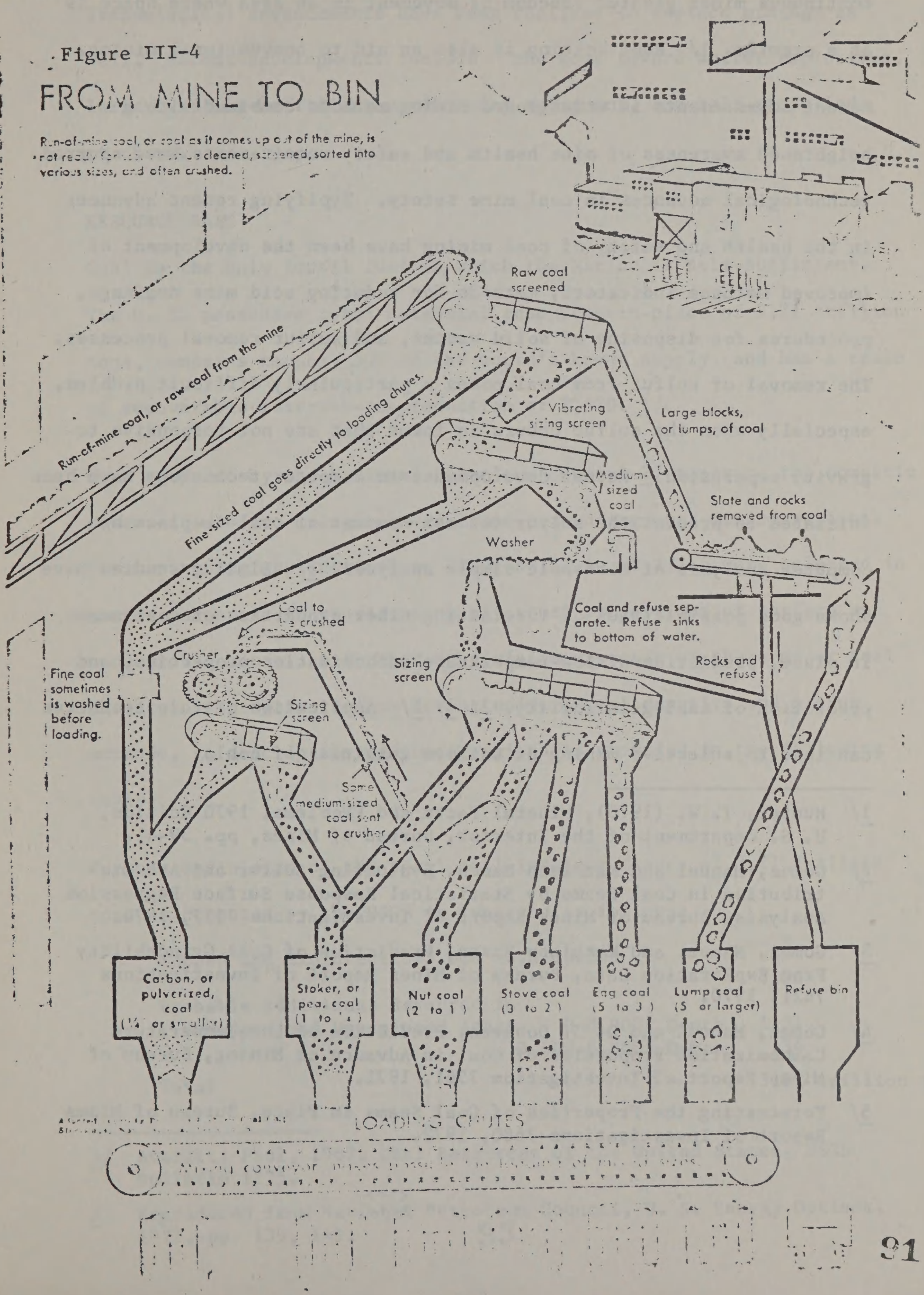

Preparation Plant
where coal is washed, weighed, and sized
Car being emptied into plant
Elevator, or cage
Fan
Air
Elevator hoist
Pipe bringing water from sump
Top soil
Sandstone
Air shaft
Fresh air is blown into the mine, or stale air is sucked out, by a big fan.
Main Shaft
Coal is loaded into railroad cars for delivery to users.
Shale
Sandstone
Limestone
Pipe carrying water to surface
Shale
Coal
Cutting machine
Loading machine
Shuttle car
Drilling machine
Loaded car ready to be hauled to the surface
Shale
Coal
Continuous miner
Shuttle car
Blasting
Limestone
Water which seeps into the mine must be pumped out constantly.
Sump
where water collects
Sandstone

Figure III-3

Once coal is mined it is sized, crushed and separated according to the procedure outlined in the following diagram. This diagram shows the processing of anthracite.

Figure III-4


FROM MINE TO BIN
Run-of-mine coal, or coal as it comes up out of the mine, is not ready for use. It must be cleaned, screened, sorted into various sizes, and often crushed.
Run-of-mine coal, or raw coal from the mine
Raw coal screened
Fine-sized coal goes directly to loading chutes.
Vibrating sizing screen
Large blocks, or lumps, of coal
Medium-sized coal
Slate and rocks removed from coal
Washer
Coal and refuse separate. Refuse sinks to bottom of water.
Coal to be crushed
Crusher
Fine coal sometimes is washed before loading.
Sizing screen
Sizing screen
Rocks and refuse
Some medium-sized coal sent to crusher
Carbon, or pulverized, coal (¼ or smaller)
Stoker, or pea, coal (1 to ¼)
Nut coal (2 to 1)
Stove coal (3 to 2)
Egg coal (5 to 3)
Lump coal (5 or larger)
Refuse bin
LOADING CHUTES
Mixing conveyor makes possible the loading of mixed sizes.

continuous miner greater freedom of movement in an area where space is at a premium. 1/ Roof bolting is also an aid to conventional mining.

Recent advancements in underground mining methods combined with a heightened awareness of mine health and safety requirements have spurred technological advances in coal mine safety. Typifying recent advances in the health and safety of coal mining have been the development of improved methane indicators, methods for reducing acid mine drainage, procedures for disposing of solid wastes, and sulfur removal processes. The removal of sulfur from coal poses a particularly difficult problem, especially when the sulfur occurs in forms that are not responsive to gravity separation. Recent developments in computer technology have been initiated to predict the sulfur and ash content of coal-in-place by computer analysis of core-hole sample analyses. 2/ Similar studies have shown good possibilities of forecasting other properties of coal seams in place, prediction of low-temperature carbonization properties, and prediction of coal grindability. 3/ 4/ 5/ Application of this technique can lead to selective mining of uniform qualities of coal.

1/ Hunter, T. W. (1970), Mineral Facts and Problems, 1970 Edition, U. S. Department of the Interior, Bureau of Mines, pp. 39-41.

2/ Gomez, Manuel and Kathleen Hazen, Evaluating Sulfur and Ash Distribution in Coal Seams by Statistical Response Surface Regression Analysis, Bureau of Mines Report of Investigations 7377, 1970.

3/ Gomez, Manuel and Kathleen Hazen, Prediction of Coal Grindability From Exploration Data, Bureau of Mines Report of Investigations 7421, 1970.

4/ Gomez, Manuel and D. J. Donaven, Prediction of Low-Temperature Carbonization Properties of Coal in Advance of Mining, Bureau of Mines Report of Investigation 7561, 1971.

5/ Forecasting the Properties of Coal Seams in Place, Bureau of Mines Report of Investigations 7680, 1972.

Technological advancements have been realized in surface mining as well. Recent developments include the move toward better explosives, larger and more efficient earthmoving equipment, and self-propelled stackers.

RESOURCE BASE

Coal is the only fossil fuel in which the Nation is self-sufficient. The U. S. possesses total potential resources-in-place of 3.21 trillion tons, contains roughly 50% of the world's known supply, and has a ratio of recoverable reserves-to-production of 2,620. 1/

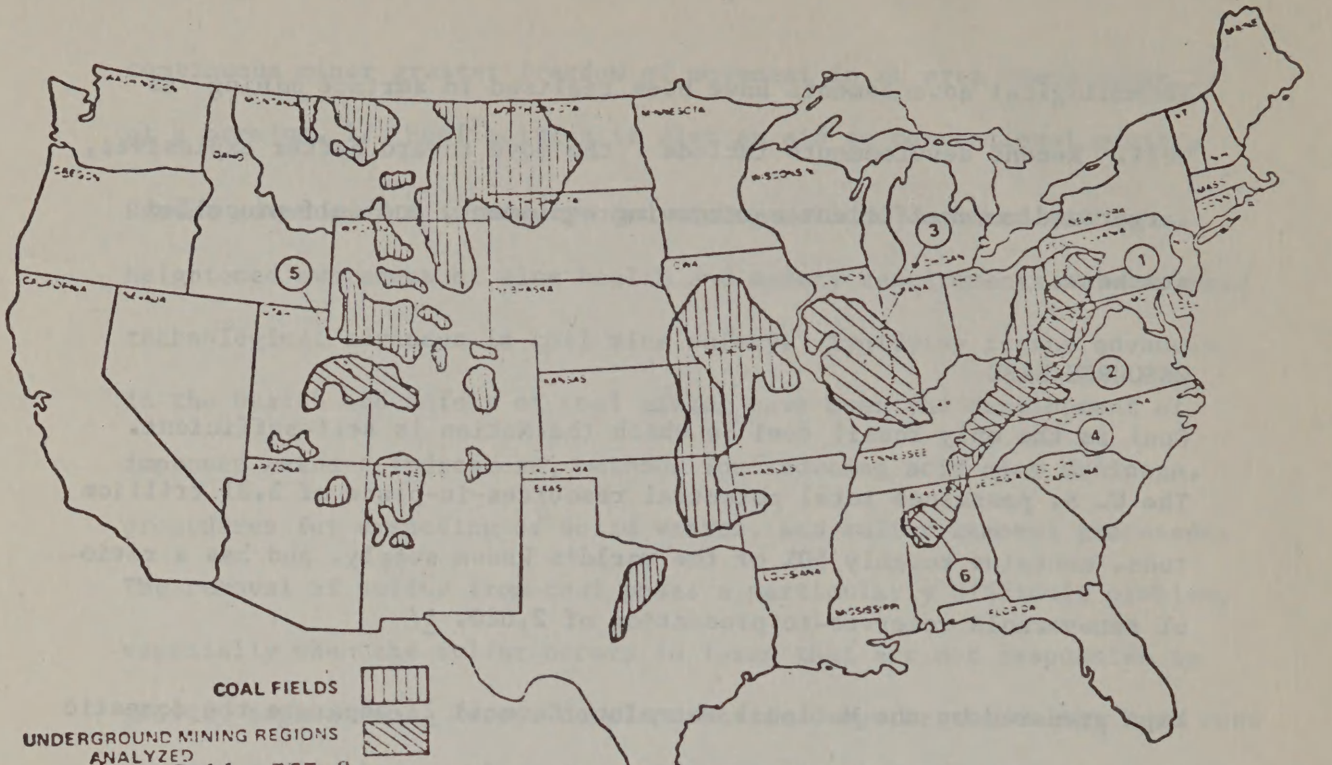
Maps prepared by the National Petroleum Council 2/ separate the domestic reserves into two categories--surface and underground mining regions. The mining regions outlined in figures III-4 and III-5 were selected in such a manner as to represent nearly equal proportions of surface and underground mines. A further subdivision was made of these major coal basins to segregate regions having uniform coal deposits and mining methods. A description of these regions is provided in the following table.

Further definition of the total coal-in-place figure of 3.21 trillion tons as computed by the USGS is reported as follows:

Mapped and Explored: 0-3,000' Overburden		1.56
Probable Additional Resource in Unmapped and Unexplored Areas:	0-3,000' Depth	1.31
	3,000-6,000' Depth	.34
Total		3.21 trillion tons

1/ Averitt, Paul, 1967, Coal Resources of the United States, USGS Bulletin 1275.

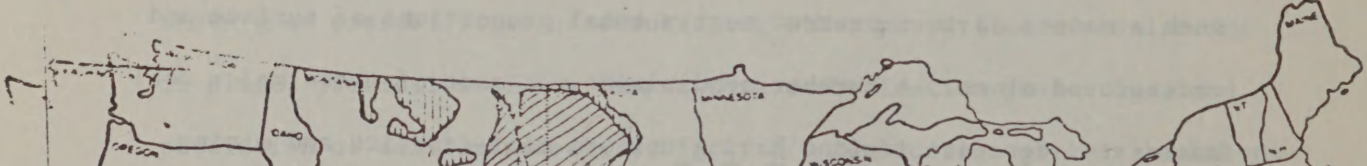
2/ Reproduced from National Petroleum Council, U. S. Energy Outlook, 1972, pp. 139, 141.



(see Table III-2

Figure III-4

Coal Fields of the United States—Major Underground Mining Regions.



(see Table III-2)

Figure III-5

Coal Fields of the United States—Major Surface Mining Regions.

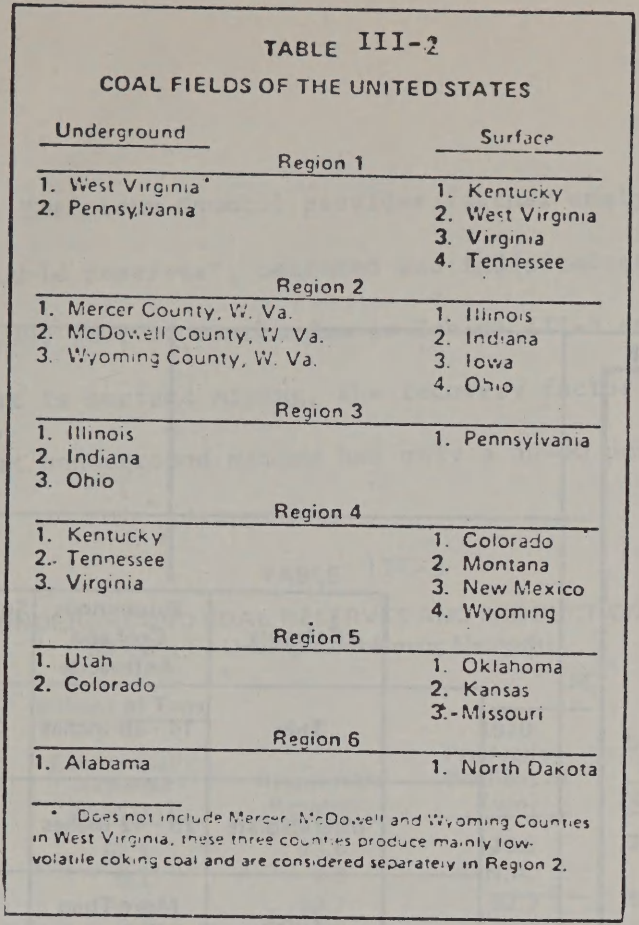


TABLE III-2

COAL FIELDS OF THE UNITED STATES

Underground	Surface
Region 1	
1. West Virginia*	1. Kentucky
2. Pennsylvania	2. West Virginia
	3. Virginia
	4. Tennessee
Region 2	
1. Mercer County, W. Va.	1. Illinois
2. McDowell County, W. Va.	2. Indiana
3. Wyoming County, W. Va.	3. Iowa
	4. Ohio
Region 3	
1. Illinois	1. Pennsylvania
2. Indiana	
3. Ohio	
Region 4	
1. Kentucky	1. Colorado
2. Tennessee	2. Montana
3. Virginia	3. New Mexico
	4. Wyoming
Region 5	
1. Utah	1. Oklahoma
2. Colorado	2. Kansas
	3. Missouri
Region 6	
1. Alabama	1. North Dakota

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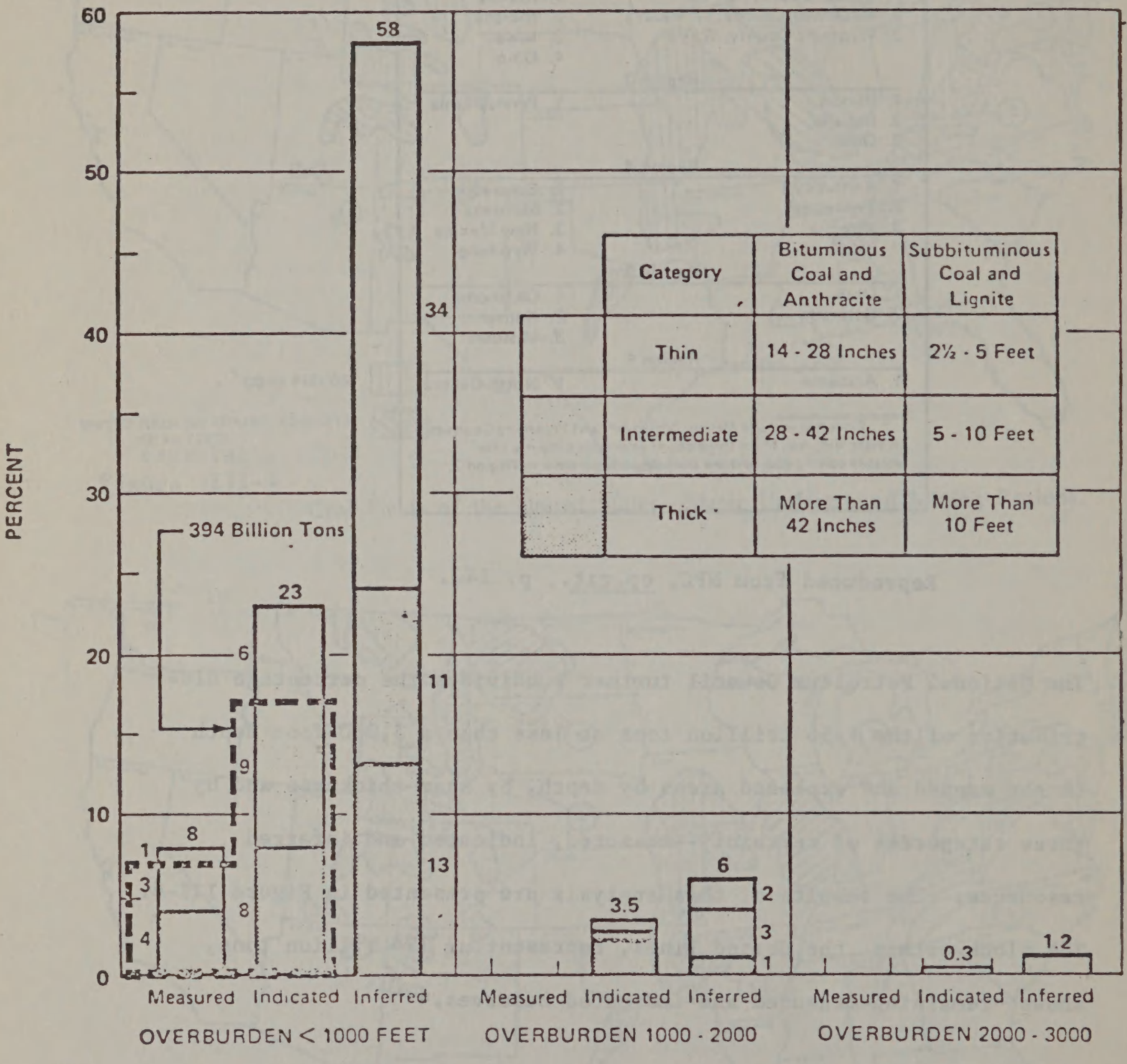
* Does not include Mercer, McDowell and Wyoming Counties in West Virginia, these three counties produce mainly low-volatile coking coal and are considered separately in Region 2.

Reproduced from NPC, op.cit., p. 140.

The National Petroleum Council further subdivides the percentage distribution of the 1.56 trillion tons at less than a 3,000-foot depth in the mapped and explored areas by depth, by seam thickness and by three categories of certainty--measured, indicated and inferred resources. The results of this analysis are presented in Figure III-6. The block within the dotted lines, representing 394 billion tons, shows "remaining measured and indicated reserves."



[illegible] Averitt, Coal Resources of the United States, *USGS Bulletin 1275 (January 1, 1967).*

[illegible] 6 Estimated Mapped and Explored Coal Resources—U.S.A. (Total Shown—1.56 Trillion Tons).

Reproduced from NPC, op.cit., p. 142.

The National Petroleum Council provides further analysis of the "economically available reserves", measured and indicated reserves covered by less than 1,000 feet of overburden in Tables III-3 and III-4. It should be noted that in surface mining, the recovery factor is 80 to 89 per cent, whereas underground mining has only a 50-60 per cent recovery factor.

TABLE III-3

UNDERGROUND COAL RESERVES AND PRODUCTION

(Minable by Underground Mining Methods)

Region	Billions of Tons: Remaining Measured and Indicated Reserves*	Billions of Tons: Economically Available Reserves†	Billions of Tons: Recoverable Reserves‡	1970 Production (Millions of Tons)	Life of Recoverable Reserves at % Growth Rate (Years): 0%	3%	5%
1	92.7	67.1	33.5	145.8	230	69	50
2	9.1	9.1	4.6	N.A.	–	–	–
3	83.1	59.5	29.7	52.3	568	96	68
4	34.5	24.4	12.2	95.0	129	52	40
5	21.9	13.3	6.7	8.6	774	106	74
6	1.6	.6	.3	9.1	35	23	20
Other	106.3	35.2	17.6	N.A.	–	–	–
Total §	349.1	209.2	104.6	338.8	309	80	58

---

* Bituminous, subbituminous and lignite in seams of "intermediate" or greater thickness and less than 1,000 feet overburden (see Figure 50).

† Excludes lignite and "intermediate" thickness seams of bituminous and subbituminous coal.

‡ Based on 50-percent recovery of economically available reserves.

§ May not add correctly due to rounding.

TABLE III-4

SURFACE COAL RESERVES AND PRODUCTION

(Minable by Surface Mining Methods)

Region	Recoverable Reserves (Billions of Tons)	1970 Production (Millions of Tons)	Life of Reserves at % Growth Rate (Years): 0%	3%	5%
1	4.2	101.2	42	27	23
2	5.6	91.0	62	36	29
3	0.8	25.1	32	23	19
4	23.8	19.1	1,246	122	85
5	1.6	8.3	193	65	48
6	2.1	5.6	375	85	62
Other	6.9	13.8	500	95	67
Total	45.0	264.1	170	61	46

A National Petroleum Council summary of the status of known and potential coal resources is presented in Table III-5.

An examination of this tabulation indicates that the greatest coal potential lies in the Rocky Mountain region followed by the Midwest. The precise extent of the reserves must be delineated through an extensive core drilling program.

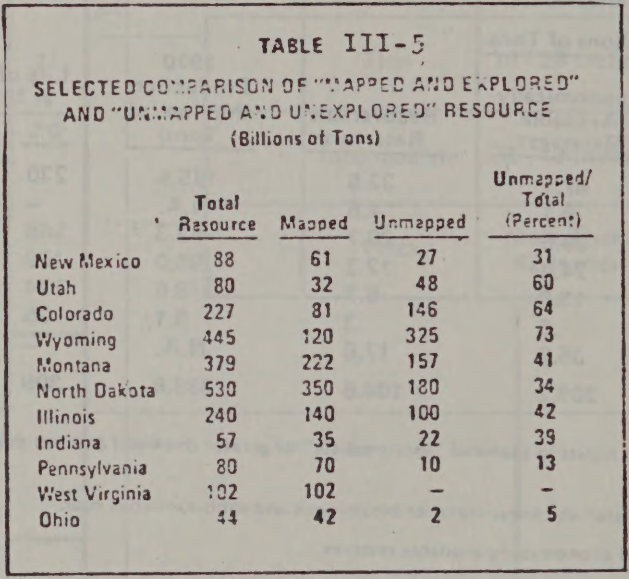


TABLE III-5

SELECTED COMPARISON OF "MAPPED AND EXPLORED" AND "UNMAPPED AND UNEXPLORED" RESOURCE

(Billions of Tons)

	Total Resource	Mapped	Unmapped	Unmapped/ Total (Percent)
New Mexico	88	61	27	31
Utah	80	32	48	60
Colorado	227	81	146	64
Wyoming	445	120	325	73
Montana	379	222	157	41
North Dakota	530	350	180	34
Illinois	240	140	100	42
Indiana	57	35	22	39
Pennsylvania	80	70	10	13
West Virginia	102	102	–	–
Ohio	44	42	2	5

ECONOMIC CONSIDERATIONS

Costs and Prices

Coal prices vary between mines, districts, states, counties and mining methods. For example the average f.o.b. coal price in 1968 was computed at $4.67. The range of prices, however, was $1.42 - $9.02 per ton.

As demonstrated in the Bureau of Mines compilation of coal prices (Figure III-7), the average f.o.b. mine price (constant 1968 dollars) per ton has declined steadily the last two decades.

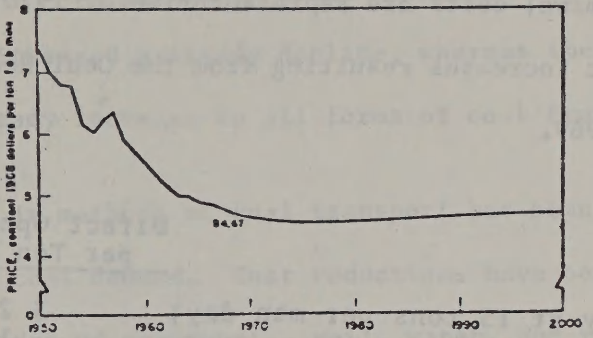


Figure III-7 Time-Price Relationship for Bituminous Coal and Lignite.

This notable price decline can be primarily attributed to increased efficiencies resulting from accelerated mechanization and a move toward strip mining in the coal industry. Competitive pressures on coal have been maintained by the generally lower price of alternate energy sources and the keen intra-industry competition. These severe competitive pressures have prompted basic research into the technologies, methods, and procedures for achieving economies in coal production.

In making coal price projections, the Bureau of Mines has concluded that a continuing increase in strip mining, which exerts a generally downward influence on average coal prices, and further increases in efficiencies at underground mines, will cause the f.o.b. mine value of coal to remain fairly stable on a constant dollar basis over time. 1/

The following tabulation provides an approximation of operating costs for a new deep mine; costs are representative of 1970 levels, but do not include cost increases resulting from the Coal Health Mine and Safety Act of 1969.

	Direct Operating Costs per Ton of Raw Coal
Labor ($40 per day at, 15 tons per man day)	$ 2.65*
Supplies	1.75
Power	.18
Payroll Tax and Compensation	.20
United Mine Workers Welfare Fund	.40
Property Tax, Insurance, Misc.	.15
Direct Administration	.10
TOTAL	$ 5.43

* The impact of productivity variations:

At 10 Tons per Man Day	+$ 1.35
At 20 Tons per Man Day	- .65

Reproduced from: National Petroleum Council, (1971), U.S. Energy Outlook, p. 135.

Transportation

Representing approximately 40 per cent of the delivered price of coal, transportation costs play a significant role in coal's competitive

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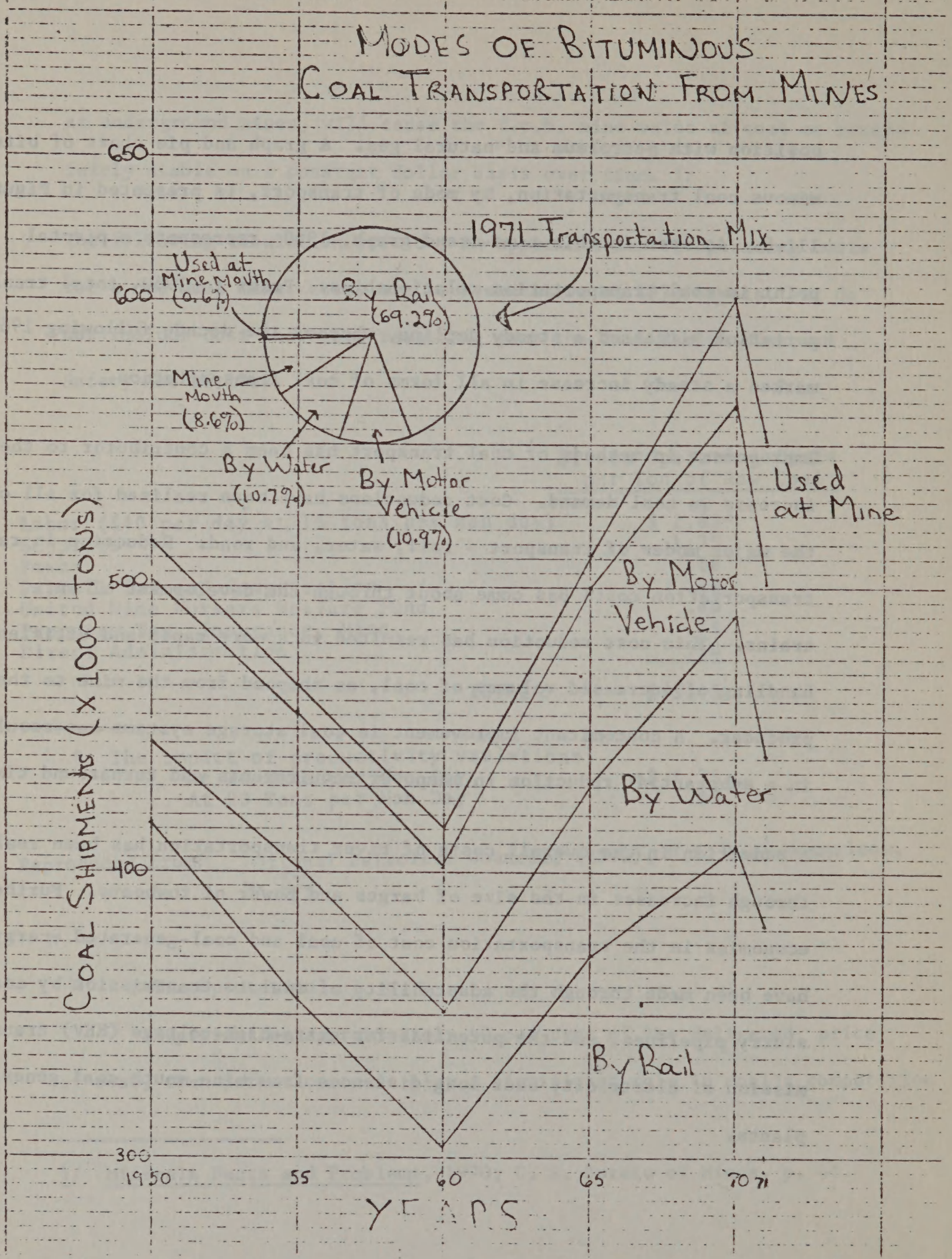
1/ Minerals Facts and Problems, 1970, U. S. Bureau of Mines, p. 46.

position with petroleum and natural gas. A graph and pie chart of bituminous coal transportation, by mode of transport, is presented in Figure III-8. As seen in this time-trend graph, 1960 represents a pivotal point in coal transportation relationships. Prior to 1960, total transportation witnessed a steady decline, whereas the decade following 1960 marked a steady increase in all forms of coal transportation.

Improvement in methods of coal transport has been a contributor to the increase in coal demand. Cost reductions have been realized for all of the major modes of transport - rail, water, and road. Reduction in rail transportation costs has come about through the development of unit trains. This cost reduction has resulted in a more rapid and efficient handling of increased volumes of coal, as shipped from the mine to the producer. A concomitant improvement in coal storage systems has resulted in a substantial reduction in manpower requirements and turnaround time.

A reduction in the overall costs of river transportation has been realized through increases in the size of barges and power of towboats. Further economies in the transportation cost of coal and coal-generated energy have been made through the adaptability of coal to transmission by coal-slurry pipelines, and the potential for extra-high-voltage (EHV) transmission of electricity over long distances from mine-mouth coal generating plants.



Compiled from National Coal Association, Bituminous Coal Facts, 1972.

Figure III-10

Supply-Demand Relationships

An evaluation of current and projected coal supply-demand relationships is strongly dominated by several factors:

1) Reserves of coal far exceed projected base for coal demand. The resource base for coal is large enough to accommodate a much faster demand growth rate, should such an increase be realized.

2) Coal has the facility to be transformed into the other fossil fuel forms such as synthetic natural gas and synthetic oil. The development of coal gasification and liquefaction will have an increasing influence on coal supply and demand.

3) The President's Energy Message of April 18, 1973, called for expanded development and utilization of our coal resources. The President supported the extension beyond 1975 for meeting secondary air standards related to the general welfare to encourage increased use of coal as opposed to oil or gas. He also urged state utility commissions to insure that utilities receive a rapid and fair return on pollution control equipment.

4) Sulfur removal technology will play an increasingly important role in the ability of the coal industry to conform to Government environmental, and health and safety regulations.

5) Natural gas and oil currently enjoy a competitive advantage over coal in the energy market. This balance should continue until the technology of coal mining, health and safety and land reclamation improves.

6) Active research and development is being carried out to improve the capacity of mining equipment, acid mine drainage control, the disposal of mining wastes (siltation of water, land quality, human aesthetics, dust control) the reclamation of strip-mined lands, the control of sulfur oxide emissions (by the physical separation of pyrite from coals, and flue stack scrubbers), and procedures to convert coal to synthetic pipeline gas and synthetic hydrocarbon liquids.

7) Manpower requirements may invoke a serious constraint on the production of coal; enrollment in mining engineering curricula had markedly declined although this trend has been reversed in the last few years.

Broken down by PAD Districts, a tabulation of national coal demand is as follows:

TABLE III-6

U.S. COAL DEMAND BY PAD DISTRICTS
(Trillion BTU's)

	1970	1975	1980	1985
PAD District I	4,745	5,394	6,071	6,871
PAD District II	6,998	8,416	9,859	11,533
PAD District III	920	1,178	1,503	1,857
PAD District IV	279	416	642	854
PAD District V	120	150	209	273
TOTAL*	13,062	15,554	18,284	21,388

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* These quantities are less than the total demand figures shown in Extract from Volume One because they do not include "Assumed Replacement for Shortfall in Other Fuel Supplies." The added quantities for coal, in terms of tons of coal, would be 30 million tons in 1975, 65 million tons in 1980 and 70 million tons in 1985.

Reproduced from: National Petroleum Council, (1971), U.S. Energy Outlook, p. 127.

The National Petroleum Council projects an increase in coal supply from present reserves under different growth rates as follows:

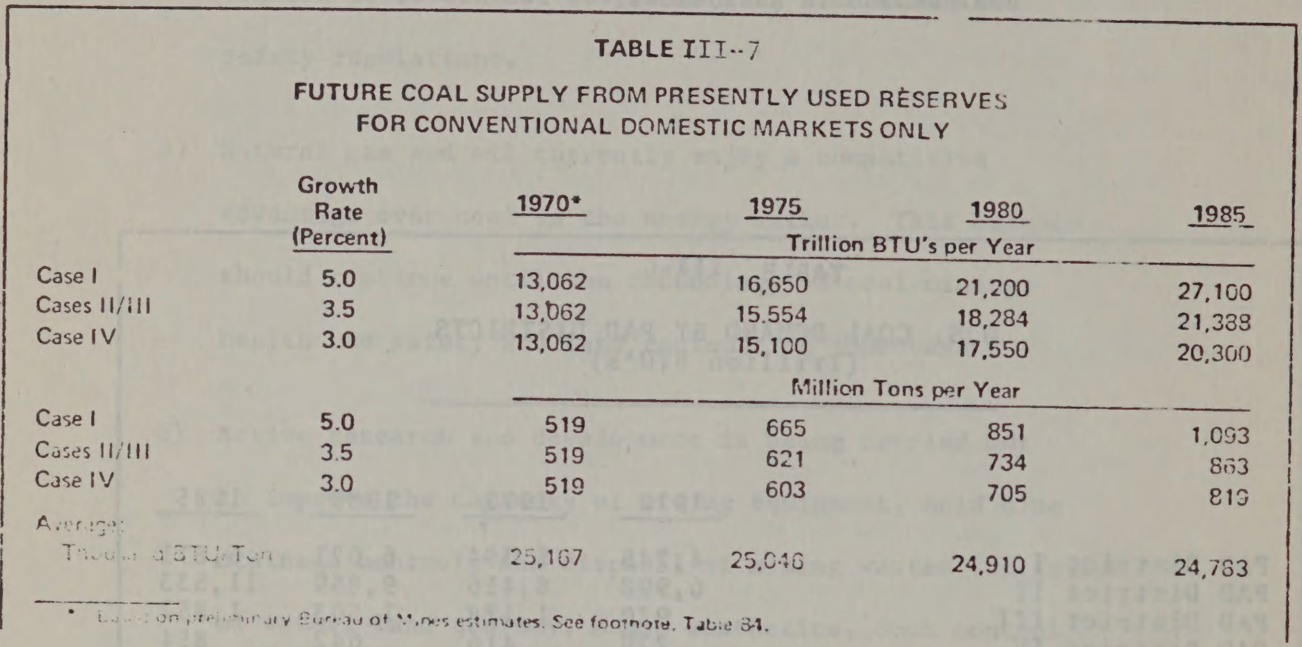

TABLE III-7

FUTURE COAL SUPPLY FROM PRESENTLY USED RESERVES FOR CONVENTIONAL DOMESTIC MARKETS ONLY

	Growth Rate (Percent)	1970*	1975	1980	1985
		Trillion BTU's per Year			
Case I	5.0	13,062	16,650	21,200	27,100
Cases II/III	3.5	13,062	15.554	18,284	21,388
Case IV	3.0	13,062	15,100	17,550	20,300
		Million Tons per Year			
Case I	5.0	519	665	851	1,093
Cases II/III	3.5	519	621	734	863
Case IV	3.0	519	603	705	819
Average: Thousand BTU/Ton		25,167	25,046	24,910	24,783

* Based on preliminary Bureau of Mines estimates. See footnote, Table 34.

Reproduced from: National Petroleum Council, (1971), U.S. Energy Outlook, p. 156.

In summary, the reserves and ability to increase coal supply are available; whether substantial increases are realized will depend in large measure on the previously mentioned seven major factors.

ENVIRONMENTAL IMPACT

Impact on Air Quality

The addition to the atmosphere of sulfurous gases is the primary harmful effect of the mining and consumption of coal. Sulfur dioxide may enter the atmosphere both when coal is mined, exposing pyrite (iron pyrite, FeS_2), and as stack gas (sulfur dioxide, SO_2) following the combustion of coal. Sulfur dioxide is present in the atmosphere in much smaller quantities than carbon dioxide and carbon monoxide, but is far more toxic. SO_2 does not accumulate in the atmosphere because it converts to sulfuric acid and sulfates; the atmospheric life of SO_2 is generally a few days. In the presence of oxygen, sunlight, and water vapor, SO_2 converts to SO_3 and then to H_2SO_4 (sulfuric acid). Sulfur may have detrimental effects on humans. In addition, prolonged exposures to SO_2 and SO_3 can cause corrosion and etching of various building materials, particularly copper alloys and building stone, concrete, and mortar containing carbonate. 1/

The sulfur content of U. S. coals ranges from 0.5 to over 7 percent. Bureau of Mines tabulations indicate that 46 percent (72,060 million tons) of the Nation's total known coal resources under less than 3,000 feet of cover contain 0.7 percent or less sulfur. Of this low sulfur content coal, 93 percent is located in the States west of the Mississippi River; for States east of the Mississippi, only 11 percent of the resources contain seven percent or less sulfur. Of this 11 percent, much of the resources are low or medium-volatile coal which is used primarily for metallurgical purposes or in steel making. The following tables provide a more detailed picture of the sulfur content of remaining domestic coal resources.

1/ Air Conservation Commission (1965), Air Conservation Report of the Air Conservation Commission, AAAS, No. 80, p. 61.

TABLE III-8

ESTIMATED REMAINING COAL RESERVES OF ALL RANKS BY SULFUR CONTENT IN THE UNITED STATES*

	Million Tons	Percent
0.7% or Less Sulfur	720,060.0	46
0.7% – 1.0% Sulfur	303,573.4	19
1.0% – 3.0% Sulfur	238,374.0	15
Over 3.0% Sulfur	314,159.0	20
Total	**1,576,166.4**	**100**

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* As of January 1, 1965.

TABLE III-9

ESTIMATED REMAINING COAL RESERVES OF ALL RANKS BY SULFUR CONTENT IN STATES EAST OF THE MISSISSIPPI RIVER*

	Million Tons	Percent
0.7% or Less Sulfur	50,062	11
0.7% – 1.0% Sulfur	45,219	9
1.0% – 3.0% Sulfur	177,281	37
Over 3.0% Sulfur	206,495	43
Total	**479,057**	**100**

---

* As of January 1, 1965.

TABLE III-10

STATES WITH LARGEST COAL CONCENTRATIONS OF 0.7-PERCENT OR LESS SULFUR

State	Million Tons
Alaska	71,115.6
Montana	154,298.9
New Mexico	38,735.0
Wyoming	35,579.7
North Dakota	284,129.1

Reproduced from: National Petroleum Council (1972), U. S. Energy Outlook, p. 160.

Compounding the problem is the fact that current transportation costs and facility limitations prevent the commercial movement of these reserves to eastern markets.

Coal, especially high-sulfur coal, is available in large quantities in close proximity to consuming markets. New coal burning plants could be built if air quality standards can be met but economics for coal desulfurization are marginal and optimistic assessments of economics are generally based on a substantial credit for sale of byproduct sulfur. Recently, the supply of sulfur has exceeded demand and the market cannot be expected to accommodate additional volumes from coal desulfurization.

Recent environmental regulations applicable to new electric generating facilities restrict the emission of sulfur dioxide to 1.2 pounds per million btu of fuel as fired; for bituminous coal, this is equivalent to about 0.7 percent sulfur. It is necessary, therefore, to reduce the sulfur content of the coal prior to burning or to remove sulfur oxides from stack gases following combustion in order that coal may continue to be used for power generation.

Mechanical cleaning of raw coal is not a solution to the problem, since only a small fraction of American coals can be cleaned sufficiently to meet sulfur emission controls and standards.

Mechanical cleaning affects only pyritic sulfur and leaves untouched the 40 to 60 percent of the sulfur that is bound in the organic structure of the coal. In addition, freeing the small particles in which pyrites occur requires fine grinding prior to cleaning, which in turn adversely affects the cleaning efficiency and restricts the methods of cleaning that can be applied.

Impact on Water Quality [1]

The major damaging environmental impacts of coal mining consist of acid mine drainage and siltation of water courses through the erosion of refuse sites. Of the two problems, acid mine drainage is the most acute.

Acid mine drainage is formed from the mining of coal in the following manner. Stripping of coal seams exposes to air and water large quantities of rock high in iron sulfides (pyrite, FeS_2). On oxidation, the pyrite breaks down forming ferrous sulfate, ferric sulfate, ferric hydroxide, and sulfuric acid. The pH of exposed soil banks is often as low as three. (pH values vary from 0 to 14, with the low range indicating acidity, the high range indicating alkalinity.) Until the pyrite has been oxidized and the acids leached from the soil, the high acidity inhibits the growth of vegetation. Experiments conducted by the Bureau of Mines on the revegetation of backfill strip mines demonstrated that by applying lime to the soils the pH of waters rose to 4.5, a decrease in acidity, increasing the survival of many plant species (Magnuson and Kimball, 1968). 1/ An additional negative effect of acid mine drainage is to further retard plant growth on the soil banks, making the banks subject to rapid erosion and increasing the sediment load of streams. The negative effects of acid mine drainage can be thwarted by the containment and treatment of acid waters and stabilization of soil banks, followed by grading and replanting of the stripped, mined out areas.

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[1] Flawn, Peter T., Environmental Geology, 1970, p. 313.

Ground and surface waters entering active underground mine workings are normally pumped to the surface for disposal. Because of the low-sulfur content of most Rocky Mountain coals, it is uncertain whether acid-mine water would be a problem in areas of large-scale mining and low average precipitation. If acid-mine water problems should develop, it is likely that the modern treatment methods employed in the coal fields of the eastern United States could be implemented to abate their impacts. The large volumes of sluge resulting from such treatment could be emplaced either in abandoned mine workings or in protected disposal areas. Drainage of acid-mine water may be prevented by locating mine entries at elevations above the prevailing drainge level, by sealing abandoned mine entries, and by emplacing dams at critical points in abandoned underground entries and haulageways.

1/ Magnuson, M. O. and Kimball, R. L. (1968), Revegetation studies at three strip-mine sites in north-central Pennsylvania: U. S. Bureau of Mines report of investigation, 7075, 8 pp.

Most coals contain undesirable constituents and must be cleaned. It is assumed that under ideal conditions, a five percent cleaner loss would occur. This problem may not be critical for surface mines where pits, from which the coal would be extracted, could receive this material. Ultimately, the mine pits would be backfilled, levelled, the top soil replaced, and the area reseeded. The problem of siltation is not as severe for Rocky Mountain area coal fields, which require little preparation before use.

Construction of slurry impoundments on underlying pervious bedrock may result in pollution of the ground water. Percolation through the base of dikes permits slurry water to reach downstream drainage systems. Unless measures are taken by coal operators to seal this type of disposal area, unfavorable impacts can continue for decades. However, use of appropriate treatment methods on the part of coal operators, coupled with effective enforcement of waste disposal regulations promulgated by State and Federal Governments, can minimize such effects on the environment.

Impact on Land Quality

Open pit mining disturbs a considerable amount of surface acreage. As of 1967, it is reported that open pit coal mines were responsible for 41 percent of the land disturbed by surface mining in the United States. 1/

1/ USDI, Surface Mining and Our Environment, A Special Report to the Nation, 1967, p. 53-54.

As an example, predictions regarding the total size of the areas which would be disturbed by the surface mining of about 20,000 short tons of coal are shown in the following table.

Climate conditions are extremely important in considering the rehabilitation of mined lands. Without proper moisture the reseeding of reclaimed lands would serve little purpose and erosion processes would soon destroy the contour of the rehabilitated lands. This problem is greater in the Western states than in the East. The following table shows the rehabilitation cost on a per ton basis for varying degrees of restoration.

In underground mining, subsidence of the ground surface is common above many abandoned and some active coal mines. The amount of subsidence relates to the mining method employed, the amount of coal removed, the thickness of the coal bed, the thickness of cover, and the composition and strength of rocks overlying the coal. Subsidence of large areas commonly destroys man-made structures and disrupts the ground water hydrology, cuts off surface and subsurface water recharge, adversely affects the quality of underground and surface waters, redirects the planned drainage of a mine, disrupts surface drainage, and, in periods of heavy rainfall, localizes flooding. It also, in some localities, causes land slides.

The most successful method of preventing or alleviating surface subsidence problems is to plan mining so that more pillars are left untouched. Unfortunately, this procedure results in less coal recovery. Pillars can

Table III-11

PRODUCTION BY SURFACE MINING METHODS

(BASED ON 1,800 TONS PER ACRE FEET)

(FIGURES BASED ON 20,000,000 TONS PRODUCTION ANNUALLY OVER 5-YEAR PERIOD)

Coal Bed Thickness (Feet)	Recovery Factor (1%)	Coal Avail. per sq. mi. @ 80% Rec. (Tons)	Area Disturbed Annually (sq. mi.)	Area Disturbed (sq. mi.)
10	80	9,216,000	2.3	11.5
15	80	13,824,000	1.5	7.5
20	80	18,432,000	1.1	5.5
25	80	23,040,000	0.9	4.5
30	80	27,648,000	0.8	4.0
35	80	32,256,000	0.7	3.5
40	80	36,064,000	0.6	3.0
45	80	41,472,000	0.5	2.5
50	80	46,080,000	0.5	2.5

be constructed of timbers and rock to make possible the mining of more coal than by simply leaving coal pillars in place to support the roof. Much additional research is needed to develop methods of underground mining which will minimize subsidence of the surface. If such methods cannot be implemented, the best solution may be to achieve as complete

Table III-12

ESTIMATED COSTS IN CENTS PER TON OF COAL FOR REGRADING, RESEEDING, AND REVEGETATING STRIP-MINED LANDS TO A PLEASING, NATURAL CONTOUR

Assumed tonnage of coal recovered per acre	Estimated costs of reclamation per acre (dollars)				
	$1,000	$2,000	$3,000	$4,000	$5,000
10,000	.10	.20	.30	.40	.50
20,000	.05	.10	.15	.20	.25
30,000	.033	.066	.10	.13	.17
40,000	.025	.05	.075	.10	.13
50,000	.02	.04	.06	.08	.10
100,000	.01	.02	.03	.04	.05

recovery of coal as possible during mining, then allow controlled subsidence to the point of natural stabilization and, finally, develop the land surface.

In addition to problems associated with land subsidence, another serious land quality problem associated with underground mining is disposal of mining wastes.

The volume of mine wastes depends on the mining method employed, the type and characteristics of top and bottom strata, the continuity of coal beds, the tonnage mined, the amount of waste material included, the specifications for which coal is being prepared, and the efficiency of processing equipment. Because costs are incurred whenever wastes are moved, mine waste piles accumulate as close to the mine mouth or open pit as possible. If these wastes are contained, either by the natural terrain or by engineering design, the only environmental effect is a man-made hill, a minor addition to topography. However, if large amounts of unconsolidated materials are allowed to accumulate without proper engineering supervision, they may become unstable and subject to mass movement. A slide in a mountain of coal mine wastes at Aberfan, Wales, in October 1966, destroyed a school and took many lives.

An additional problem with coal mining wastes concerns dust from debris piles. The most commonly used technique of preventing widespread scattering of mining and processing wastes is to compact the waste layers, followed by sealing with incombustible soil, after which vegetation is established to prevent infiltration of surface water and to minimize erosion. An alternative to surface disposal of mine and coal processing waste is to return wastes to abandoned underground mine workings. This is currently being done to control surface subsidence in mined areas in compliance with restoration provisions of the Appalachian Regional Development Act of 1965, as amended. Methods of returning the waste to mined out areas concurrent with active mining would appear to warrant attention of mining method researchers.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

To replace the expected energy from the proposed MAFLA sale (1.917 to 3.106 trillion Btu/day) with energy from coal would require the utilization of 29 to 47 million tons of coal per year. An increase of this magnitude could be supported by existing U. S. proved reserves. The primary constraints would be economic and environmental.

If this increased coal were provided by surface mining, it is believed that 6-10 mines of five million short tons annual capacity would be needed. One mine of this size would employ about 600 persons and have a capital cost of $40 million. To supply the necessary incremental amount would require 3,600 to 6,000 employees and capital expenditures of $240-$400 million.

If underground mines were used, 15 to 24 mines of 2 million ton annual capacity would be required. Manpower for these operations would be 26,500 to 42,100 and capital expenditures would range from $363 to $580 million.

If the energy for this sale came from surface mined coal, one major consideration would be the amount of land disrupted by mining. The following table gives an indication of how much land would be disturbed in the surface mining of about 50 million tons/year.

Land Disturbed In Surface Mining Production
(Based on 1,800 tons per acre foot)

(Figures Based on 50 Million Tons Produced Annually)

Coal Bed Thickness (feet)	Recovery Factor (%)	Coal Available (million Per Sq. Mile tons)	Area Disturbed Annually (Sq. Mile)
10	80	9.216	5.4
15	80	13.824	3.6
20	80	18.432	2.7
25	80	23.040	2.2
30	80	27.648	1.8
35	80	32.256	1.6
40	80	36.064	1.4
45	80	41.472	1.2
50	80	46.080	1.1

4. Synthetic Sources of Oil and Gas

A. Oil Shale

TECHNOLOGICAL PROCESSES

U.S. has abundant oil shale resources that offer great potential to supplement conventional supplies of oil and gas. These resources have not been developed in the past because of availability of oil and gas from conventional sources at lower development costs. However, present and projected energy shortages have focused attention on the energy promised by oil shale.

The major options for oil shale development are: (1) mining followed by surface processing of the oil shale and shale-oil; and (2) in-situ (or in place) processing. The relative state of knowledge of the various operations required in oil shale processing is shown in Figure IV-2 1/. It is apparent from Figure IV-2, however, that various technical approaches are available for each phase of the operations, and no single system is likely to dominate the initial development of oil shale.

Until recent years, virtually all efforts to develop oil shale technology were directed toward mining, crushing, and above-ground retorting. Oil shale processing in this manner would require the handling of large amounts of materials. Figure IV-2 indicates the materials flow through such

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1/ Most of the refining operations shown in Figure IV-2 would be performed outside of the oil shale region at refinery centers near markets for the products. Figures IV-1, IV-2 and IV-3 are from the Final Environmental Statement for the Prototype Oil Shale Leasing Program, U. S., Dept. of Interior, August 1973, Volume 1.

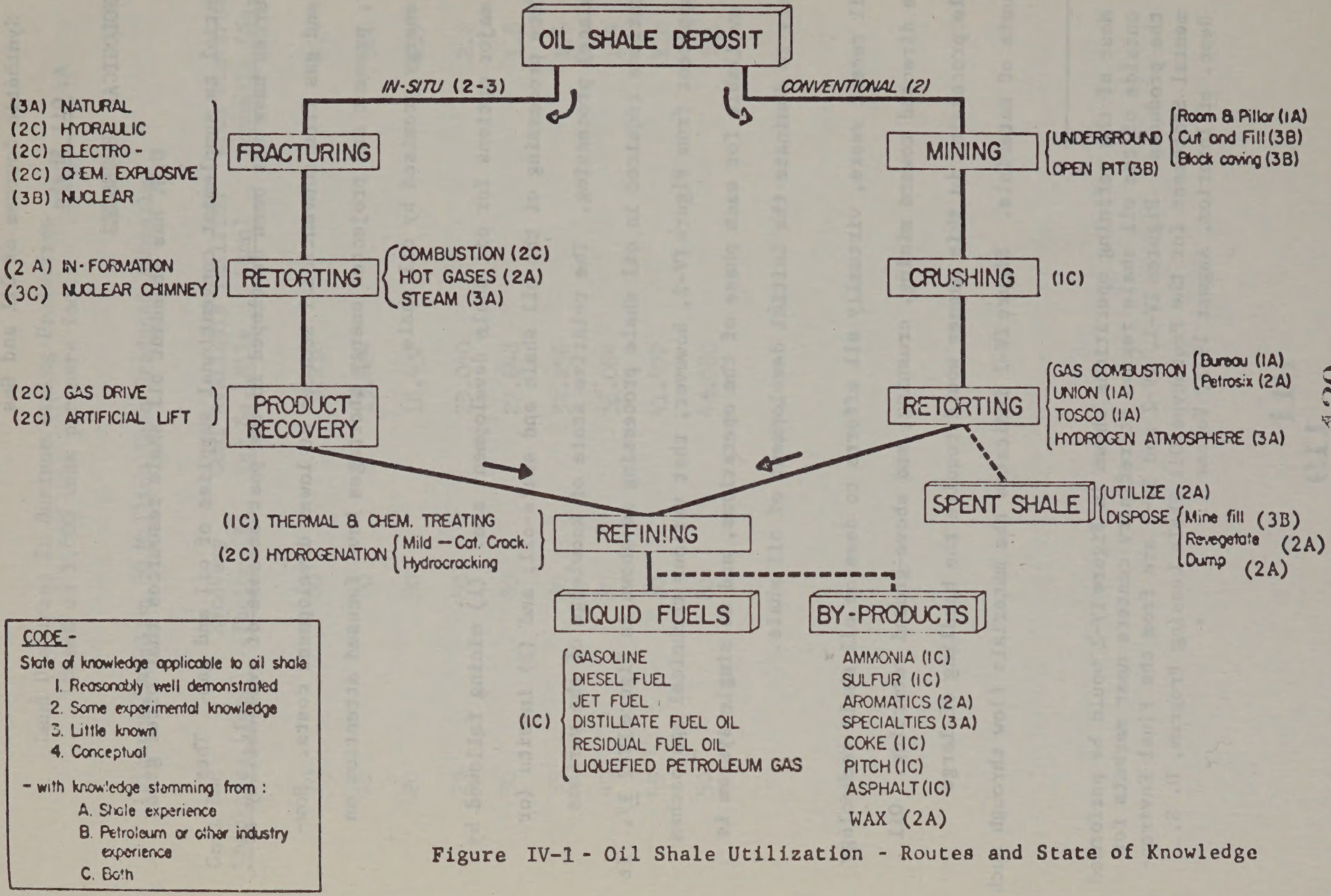


Figure IV-1 - Oil Shale Utilization - Routes and State of Knowledge

an operation, beginning with mining and ending with final fuel products and various by-products. In certain locations, the oil shale deposits contain minerals that may be amenable to recovery of additional by-products such as soda ash and alumina.

Oil shale mining can be conducted either at the surface or underground. The former, usually described as open-pit mining, involves removal and disposal of the surface material or overburden, followed by mining the underlying oil shale in a quarry-like operation. The quantity of overburden significantly affects the development time and economics. Current open-pit techniques and existing large-scale equipment are expected to enable mine development at relatively low costs, although disposal - restoration costs will be greater than similar costs for underground operations.

The room-and-pillar method has been extensively tested for underground mining of oil shale. In this development plan the recovery rate would depend on the depth and local conditions. In general, about 60% of the shale can be removed. The remainder is left as pillars for mine support and to prevent surface subsidence. It is expected, however, that some mining operations would provide substantially lower total extraction percentages. Room-and-pillar mining is characterized by large rooms over 60 feet in height, separated by the support pillars. Access to the oil shale to be mined can be gained from the surface either by a vertical shaft, or a horizontal adit or tunnel.

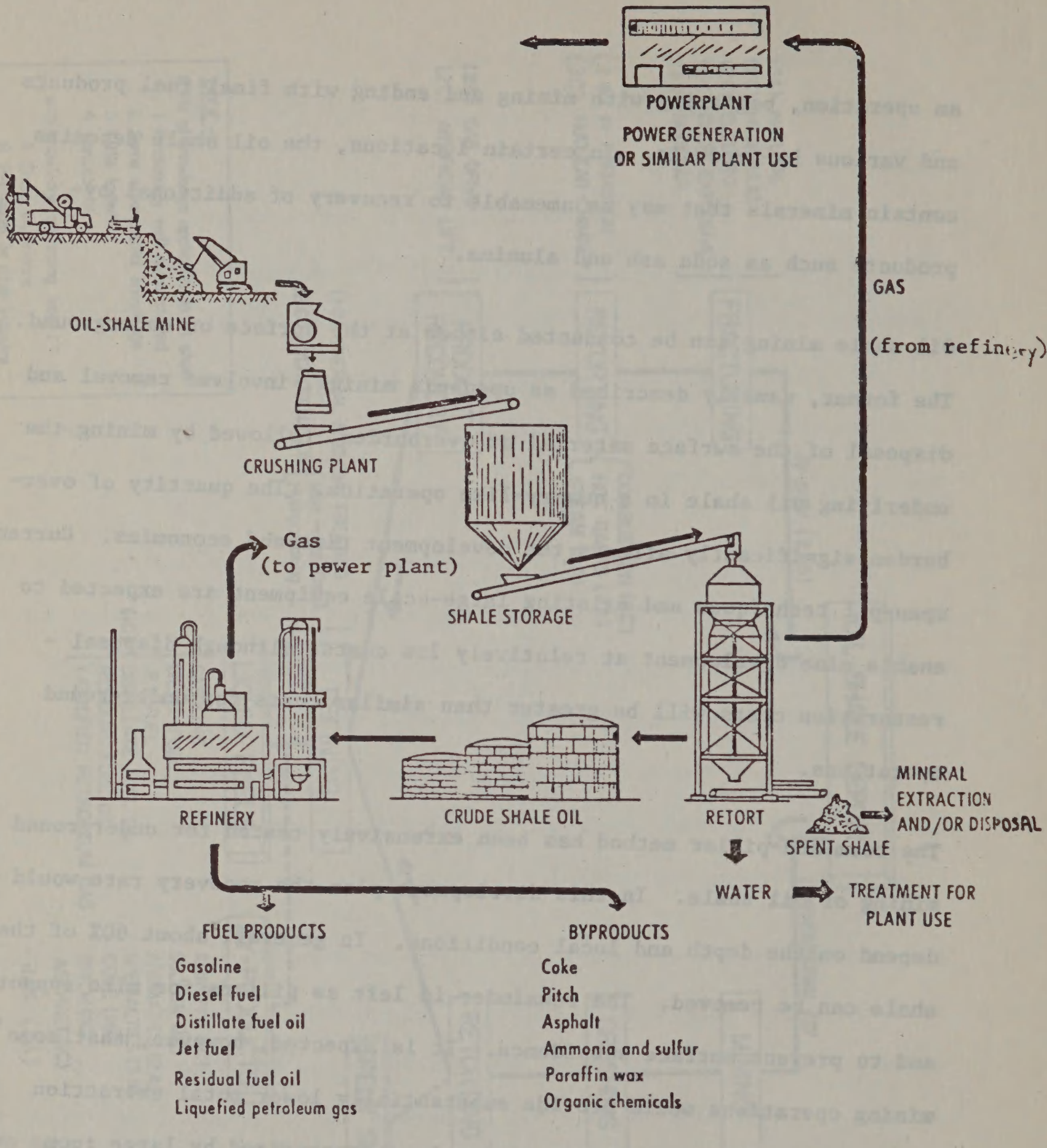


Figure IV-2 –Schematic Diagram of Oil Shale Surface Processing

Crushing and conveying systems are technically and economically well-established and are regarded as necessary parts of any integrated processing system. The selection of specific equipment is primarily based on the size of the oil shale fragments needed for subsequent processing.

Literally thousands of retorting processes have been patented worldwide for the production of oil from oil shale. Three processes that have been tested using large experimental equipment appear at this time to offer reasonable possibilities of technical and economic success if scaled up to commercial design size. These retorting methods include the Gas-Combustion process developed by the Bureau of Mines, the Oil Shale Corporation (TOSCO) process, and the Union Oil Company process. In each system, heat is applied to raise the temperature of the oil shale to about 900 degrees F., where the solid organic material (kerogen) is converted to a liquid. The equipment, method of heat application, and operating procedures differ markedly for each system.

Oils from the retorting processes, with the possible exception of the TOSCO process, will require upgrading before the oil can be transported through pipelines to the final product refineries, which are expected to be located outside of the oil shale region. Modern refinery processes are suitable for subsequent upgrading. Each of the three retorts also produces a retort gas that may be used within the plant as a fuel, or alternatively, to generate supplemental electrical power for nearby communities.

Spent shale may be in the form of soild particles ranging from 10 inches in diameter to a fine powder, depending on the retorting method used. It will normally be dry, but it may be wet if it is processed to recover saline minerals. Disposal will therefore depend on the physical characteristics of the material, its water content, and the location of the disposal area, whether surface or subsurface. If it is to be returned to the mine, this will affect the mine development plans.

Various processes for recovery of the saline minerals associated with the oil shales have been proposed.

The economical recovery of alumina, soda ash, and nahcolite (potentially valuable for removal of sulphur oxides from stack gases) from the deep oil shales has not yet been demonstrated on a large scale nor have the effects of their recovery been tested by current markets for these chemicals.

An alternate mining and processing technique, called in-situ processing, would involve the recovery of oil from the shale by heating underground, in place. Presently proposed heat sources for the in-situ recovery include underground combusting, hot natural gas, hot carbon dioxide, superheated steam, hot solvents, and combinations of two or more of these. It is anticipated that conduits for introducing heat underground would be provided by wells, mine shafts and tunnels, fractures created by a variety of techniques including nuclear explosives, or by a combination of these.

Figure IV-3 shows a design concept for conventional in-situ retorting based on contemporary petroleum technology. The essential steps include 1) well drilling, 2) fracturing to permit heat transfer and movement of liquids and gases, 3) application of heat, and 4) recovery of products.

Despite considerable laboratory and field research, in-situ processing has not been successfully developed or demonstrated on a large scale. Two problems have been 1) insufficient naturally occurring permeability, or failure to artificially induce permeability in order to permit heat transfer and passage of gases and liquids, and 2) inability to remotely control the process with sufficient accuracy through wellbores from the surface. Additional problems if nuclear explosives are used are possible ground motion and release of radioactivity.

RESOURCE BASE

Oil shale deposits are found in many areas of the U.S. but many are low grade, small, and inaccessible. The richest deposits occur in the Green River Formation in Colorado, Wyoming, and Utah in large topographic basins that are identified by streams draining most of the land surface. These include the Green River Basin and Washakie Basin in Wyoming, the Uinta Basin in Utah, and the Piceance Creek Basin in Colorado. Oil shale of possible commercial interest also occurs in Battlement and Grand Mesas in Colorado. These oil shales are found beneath 25,000 square miles (16 million acres) of land, of which about 17,000 square miles (11

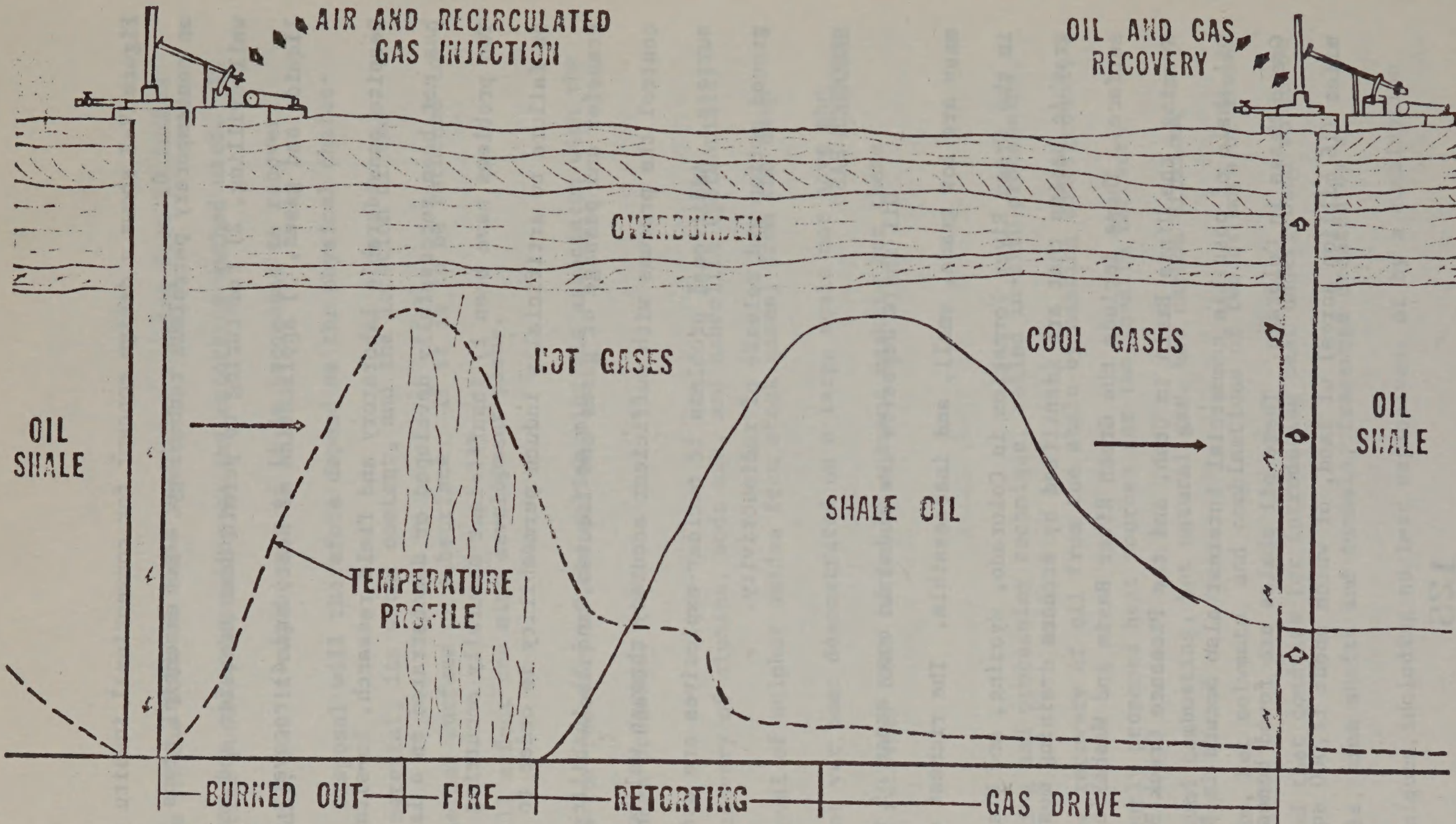
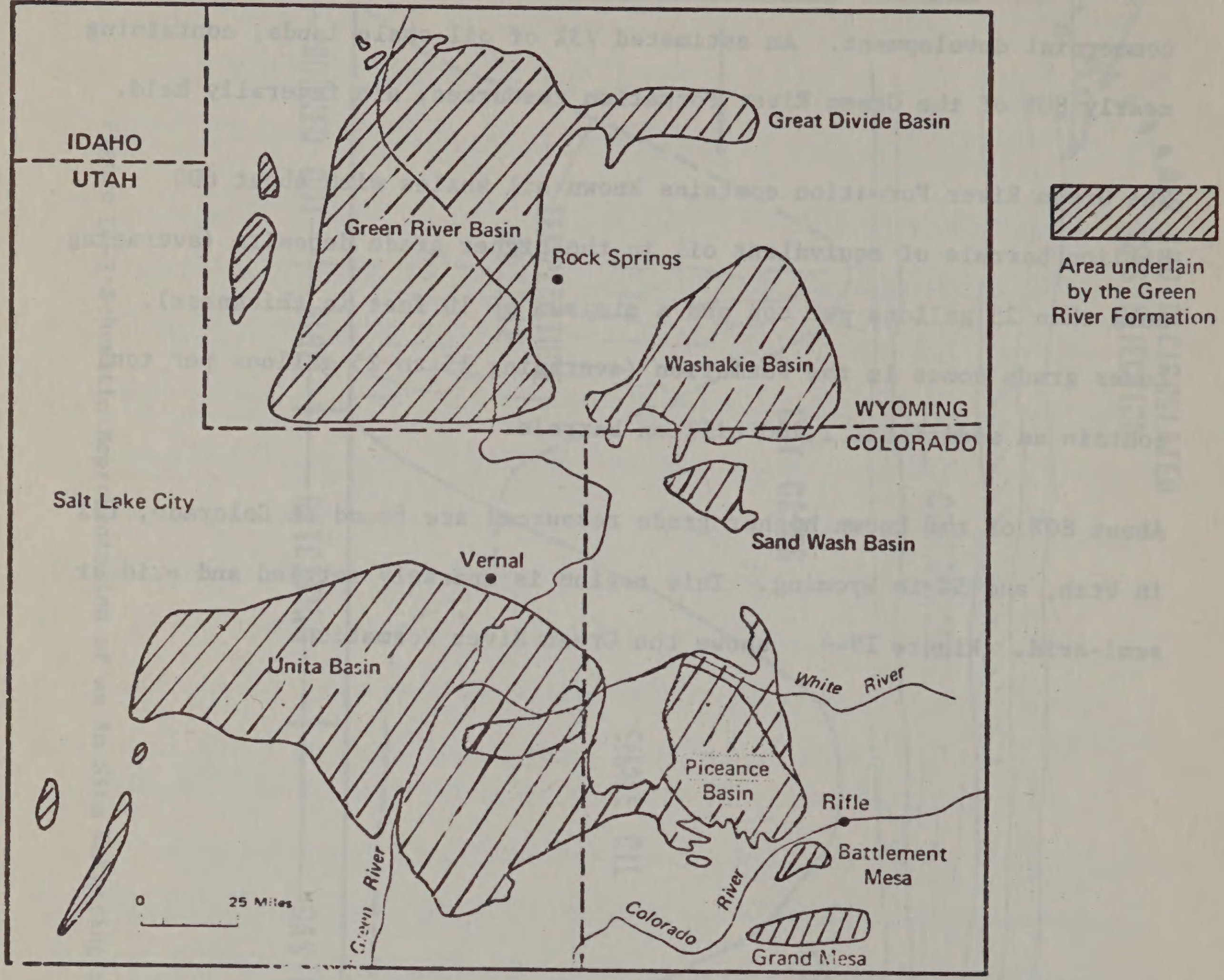


Figure IV-3-Schematic Representation of an In Situ Retorting operation

million acres) are believed to contain oil shale with potential for commercial development. An estimated 73% of oil shale lands, containing nearly 80% of the Green River Formation resources, are federally held.

The Green River Formation contains known oil shales with about 600 billion barrels of equivalent oil in the higher grade deposits (averaging more than 25 gallons per ton and a minimum of 10 feet in thickness). Lower grade zones in the Formation (averaging 15 to 25 gallons per ton) contain an additional 1,200 billion barrels.

About 80% of the known higher grade resources are found in Colorado, 15% in Utah, and 5% in Wyoming. This region is sparsely settled and arid or semi-arid. Figure IV-4 shows the Green River Formation.



Source: U.S. Energy Outlook, A report of the National Petroleum Council's Committee on U.S. Energy Outlook, Dec., 1972.

Figure IV-4 . Oil Shale Reserves of the Green River Formation.

The National Petroleum Council gives the following breakdown of reserves based on commercial attractiveness:

Classes 1 and 2.	The most accessible and better defined of the deposits at least 30 feet thick and averaging 30 gallons of oil per ton of shale. Class 1 averages 35 gallons per ton over a continuous interval of at least 30 feet.
Class 3.	Deposits as rich as Classes 1 and 2 but more poorly defined and not as favorably located.
Class 4.	Low grade, poorly defined deposits.

Table IV-1

Oil Shale Resources of the Green River Formation

(Billion of Barrels)

Location	Class 1	Class 2	Class 3	Class 4	Total
Piceance Basin - Colorado	34	83	167	916	1,200
Uinta Basin - Colorado & Utah		12	15	294	321
Wyoming			4	256	260
Total	34	95	186	1,466	1,781

Source: U.S. Energy Outlook, A report of the National Petroleum Council's Committee on U.S. Energy Outlook, Dec., 1972.

ECONOMIC CONSIDERATIONS

Projections of capital investment, prices of shale oil, and rate of development are dependent on each other and on assumptions concerning industry and government policies, technology, and required rates of return. The National Petroleum Council gives estimates of possible development under four sets of conditions. Case I represents the maximum feasible production under non-emergency conditions and assumes shale oil prices adequate to encourage commercial development. Limitations on rate of development include availability of operating personnel, environmental restrictions, lack of supporting commerce and industry, and construction logistics. Cases II, III, and IV show slower rates of investment due to lack of investment incentive or need for time to demonstrate process feasibility. Table IV-2 shows production rates under each set of conditions.

Table IV-2 . Production of Shale Oil (MB/D)

	1975	1980	1985
Case I	0	150	750
Case II	0	100	400
Case IV	0	0	100

Source: U.S. Energy Outlook, Dec., 1972. p. 205.

Price predictions are sensitive to the rate of return desired and the shale assay. "Price" developed by the National Petroleum Council is exclusive of transportation costs to refineries ($0.50 to $0.75 per barrel), leasing costs, or bonus payments. These prices are based on invested capital to build and equip two mines, two retorts, and one upgrading plant to produce 100 MB/day of shale oil. Table IV-3 shows these prices.

Table IV-3 Required Shale Oil "Prices"
(Dollars per barrel)

Discount Cash Flow Rate of Return (%)	30 gallons/ton oil shale	35 gallons/ton oil shale
10	4.32 - 4.47	3.97 - 4.09
15	5.58 - 5.79	5.10 - 5.29
20	7.03 - 7.29	6.45 - 6.72

Source: U.S. Energy Outlook, Dec., 1972. p. 206.

The detailed assumptions used in developing these projections are described in U. S. Energy Outlook. Prices will be influenced by royalty rates, depreciation and depletion allowables, and investment tax credit provisions.

On June 29, 1971, the Secretary of the Interior announced plans for a proposed prototype oil shale leasing program which would make available to private enterprise, for development under lease, a limited amount of public oil shale resources. Such leases would be by competitive bonus bidding and would include assumption of certain royalty obligations to the United States.

The following exerpt from the final Environmental Statement for this program[1/] describes the rate of oil shale development that may be expected.

For purposes of the present discussion, it is assumed that private lands would support no more than 400,000 barrels per day and that the six prototype tracts would support a total of 250,000 barrels per day. The combined output from private and public holdings would then reach 650,000 barrels daily by 1985. Additional public lands would be required to increase the production rate above this level. Even if suitable lands are available, the rate of development will be determined by the logistics of plant construction and by manpower constraints. Under these constraints, the Department of the Interior estimates the maximum 1985 production to be 1 million barrels per day. Even at this rate of production, only about 9 percent of the 80 billion barrels of prime commercial interest would be produced by the year 2000. The ultimate size of the oil shale industry will most likely not be determined by the magnitude of the oil shale resource base but will probably be limited by other factors such as the availability of water, for example.

[1/] Final Environmental Statement for the Prototype Oil Shale Leasing Program", released August 1973 by the U. S. Department of the Interior; Vol. I, p. III-7.

ENVIRONMENTAL IMPACT

Impact on Land Quality

The development of an oil shale industry would require roads, mining, plant sites, waste-disposal areas utility and pipeline corridors, and associated services during the productive life of a lease. These activities would change the existing pattern of land use, alter the existing topography and would affect natural vegetative cover until revegetative operations began. Such disturbances would unavoidably exist throughout the life of operations, but would be temporary in the sense that restoration of surfaces to original or improved condition would be required before site abandonment. Table IV-4 shows the amount of land that would be required for a 100,000 bbl./day surface mining operation, a 50,000 bbl./day underground mine operation, and a 50,000 bbl./day in situ operation.

Waste disposal could be deposited in canyons and gullies which would gradually be converted into flatter areas. Contouring and revegetation would restore scenic attractiveness and probably reduce erosion.

Where areas to be developed are now used for livestock grazing, agriculture, wildlife habitat, or recreation, some unavoidable loss in these patterns of land use would result.

1/ This discussion is taken from the Final Environmental Statement for the Prototype Oil Shale Leasing Program, U. S., Dept. of the Interior, August 1973.

TABLE IV-4 ---Land Requirements for Oil Shale Processing

Function	Land Required (Acres)
Mining and waste disposal:	
Surface Mine1/2/ (100,000 bbl/day):	
Mine development	30 to 85 per year
Permanent disposal, overburden	1,000 (total)
Temporary storage; low-grade shale	100 to 200 (total)
Permanent disposal; processed shale	140 to 150 per year
Surface facilities 3/	200 (total)
Off-site requirements5/	180 to 600 (total)
Underground Mine2/ (50,000 bbl/day):	
Mine development (Surface facilities)	10 (total)
Permanent disposal:	
All processed shale on surface	70 to 75 per year
60 percent return of processed shale underground	28 to 30 per year
Surface facilities3/	140 (total)
Off-site requirements	180 to 225 (total)
In situ processing (50,000 bbl/day):	
Surface facilities 3/	50 (total)
Active well area and restoration area4/	110 to 900
Off-site requirements	180 to 600 (total)

1/ Area required is dependent upon the thicknesses of the overburden and oil shale at the site. Acres shown are for a Piceance Creek Basin site, with 550 ft. of overburden and 450 feet of 30 gallon/ton shale (approximately 900,000 bbl/acre).

2/ Assumes 30 gallons per ton oil shale and a disposal height of 250 feet.

3/ Facilities include shale crushing, storage and retorting (excluded for in situ processing), oil upgrading and storage, and related parking, office, and shop facilities.

4/ See Volume III, Figure III-10, for conceptual view of surface utilization.

5/ Includes access roads, power and transmission facilities, water lines, natural gas and oil pipelines; actual requirements depend on site location. A 60-foot right-of-way for roads requires a surface area of about 8 acres per mile. Utility and pipeline corridors 20 feet in width require 2.4 acres per mile.

Source: Final Environmental Statement for the Prototype Oil Shale Leasing Program, U. S. Dept. of the Interior, August 1973, Vol. I, p. III-12.

Impacts would be significant in local areas but slight for the region as a whole because the percentage of the region's total surface area affected by development (including urbanization) would be small. However, the semi-remote character of the area would be modified and some local dislocations would unavoidably occur.

Impact on Water Quality

One of the greatest possible impacts would be the requirement of large amounts of water for retort plants and the disposal of waste water. Approximately 150,000 acre-feet annually would be required for one million barrels per day of shale oil production.

In addition, as much as 10 gallons of water per ton of shale could be produced in the surface retorts. This water could contain dissolved saline and organic compounds. It could be used to moisten the waste shale to prevent dust problems. However, it would require treatment prior to other uses to remove hydrocarbons and malodorous compounds, and perhaps dissolved minerals.

Large quantities of natural ground water occur in leached zones of the deep oil shale areas, but the location, composition, and movement of such waters have yet to be defined in many areas. These aquifers may contribute substantially to the overall water supply available to satisfy requirements for oil shale development. Other sources are the Colorado River and its tributaries. To insure dependable supplies from these rivers might require construction of dams and reservoirs or purchase of water from existing reservoirs.

Use of ground water in oil shale development could decrease the natural discharge of springs and seeps. This could result in adverse effects on associated vegetation, and any fish or wildlife dependent on that water supply. Careful lease site selections to avoid natural water features which provide aquatic habitat and/or development of alternate water sources for wildlife would prevent or mitigate such effects.

Degradation of water quality could occur from discharge of product or waste waters, siltation of streams, or leaching of saline minerals from spent shale. It could be avoided in most cases by proper design, equipment, and adequate supervision and monitoring of operations. Leaching of spent shale would not be expected to be a problem because properly emplaced waste sites will harden through natural cementation.

In addition to these waters, there would possibly be a water slurry produced by a wet scrubbing process used to remove fine dust in gas streams. The slurry from the wet scrubbing could be used to wet the spent shale.

Water would also be used in the cooling phase of the process, but the amount needed could be kept to a minimum by employing air cooling. Any "sour" water streams produced by accidental contact with oil in final water condensers would be treated by conventional oil refinery methods.

The nature of the foreseeable problems associated with water quality would depend largely upon the mineral characteristics of the processed shale and the method of disposal. The foreseeable problems, as outlined, are believed controllable with present technology.

Impact on Air Quality

Proper techniques already exist to adequately control emissions, including particulates, sulfur oxides, and nitrogen oxides potentially present in various fuel gases, and the dusts produced in mining and shale disposal. It is expected that all applicable Federal and State criteria on acceptable air quality standards could be met. Residual concentrations of sulfur oxide, on the basis of a 200,000 bbl/day output, would total 12 to 40 tons per day depending on the process,and nitrogen oxides would total 17 to 23 tons per day. Solid particulates in gaseous discharges to the atmosphere would be small, but unavoidable at the present state of technology. New control techniques now being developed for other industrial operations could be incorporated into this industry. Some local problems with temperature inversion may be experienced, the significance of which cannot now be established. The long term effect of industrialization would result in a decline in general air quality of the region.

The local noise level near developed sites is expected to increase, due to mining, retorting, and other processing operations. This is an unavoidable adverse consequence of increased industrial activity in a region which is presently predominantly a semi-wilderness, and can be only partially mitigated by noise abatement devices.

Impact on Fish and Wildlife

Construction and operation would have varying degrees of direct and indirect impacts upon fish and wildlife and their habitat in the immediate vicinity of the plants and along roads, surface facilities, and pipelines. Noise and associated human activities accompanying construction and operation would have a new effect of stress and disturbance on normal behavior and activity patterns of wildlife. Species which could be affected by such disturbances include mountain lion, bear, elk, mule deer, antelope, bob cats, sage grouse, blue grouse and migratory birds. Encroachment of humans causes loss of habitat, and often adjacent areas cannot support the displaced animals.

Air strips and increases in air traffic would provide some source of aerial harassment of mule deer, wild horses, and big game, the extent of which would be dependent upon the number and location of air strips and the volume of air traffic which would be involved.

Wildlife food and cover values of lands used for mining, pipeline and road construction, building, etc., would be at least temporarily lost. Permanence of such losses would be dependent upon the time required for and success of reestablishing useful wildlife food and cover. Such habitat loss would in turn result in lower populations of animals. For example, removal of critical winter browse would result in a corresponding reduction in mule deer numbers.

Oil shale-related drying of surface water features, such as springs, seeps, and small streams, would change the natural plant-animal complex associated with each particular water feature, including the related distribution of game, wild horses and cattle.

Coverage of roadside vegetation with vehicle-caused dust would constitute a minor but chronic problem, since such vegetation would lose its wildlife food value until washed off by subsequent rains.

Unpredicted or uncontrollable changes in the quality of local surface or ground water would result in accompanying impacts on aquatic fish and wildlife populations and their habitat. In the event that sediment, leached substances, saline ground waters and/or toxic materials were released to surface waters as a result of oil shale operations, adverse impacts would be imparted to aquatic plant and animals. Unless carefully controlled, such discharges would have adverse effects on aquatic habitat of the Colorado, Green and White Rivers and other exposed water areas. Adverse impacts would also be expected in exposed aquatic habitat in the form of lowered biological productivity, physical covering of fish spawning and nursery areas.

Handling, storage, and transmission, including feeder pipelines, would exhibit some small losses of oil. Spills would follow natural drainage features and released oil would kill trees, shrubs, and other vegetation with which it came into contact. Birds, some species of both land and water mammals, and fish and other aquatic organisms would be adversely affected if they came in contact with the oil.

Oil shale-related urbanization would also create stress on regional wildlife populations. Reductions in surface water quality near population centers as a result of sewage, toxic substances and siltation, would adversely affect aquatic organisms and their habitat. Some wildlife habitat would be consumed by buildings, roads, parking lots, etc. Additional wind and water erosion would occur. Increased ground vehicle traffic would result in more frequent road kills of deer and other game.

Increased hunting pressure would cause localized adverse impacts upon wildlife through reduction of populations of some species, including a few already scarce species such as the brown bear and cougar. Increased harvest of mule deer, elk, moose and antelope would require regulation in order to avoid undesirable downward population trends. Both development and associated urbanization would aggravate conditions which cause some species to be classified as rare and endangered. Semi-remote hunting and fishing qualities would be lost.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

Under this alternative, the expected oil and gas from the MAFLA sale would be replaced by 331,000 to 536,000 barrels a day of oil produced from oil shale. Since the oil shale industry in the U. S. is in its earliest stages, it is difficult to predict the magnitude of impacts associated with a given level of production. The Department of Interior, in its Final Environmental Statement for the Proposed Prototype Oil Shale Leasing Program, estimated the impacts for the Green River Formation region.

Their estimates are based on a "unit tract" with a production level of 50,000 barrels daily for underground mines and 100,000 barrels daily for surface mines. Using these estimates, land requirement projections are given below for production of 331,000 barrels a day.

Surface Mining	Land required, acres
Mine development	100 to 280 yearly
Permanent Disposal, overburden	3,300 total
Temporary Storage, low grade shale	330 to 660 total
Permanent Disposal, processed shale	460 to 495 yearly
Surface facilities	660 total
Off-site requirements	595 to 2,000 total

Underground Mining

Mine development	66 total
Permanent disposal*	185 to 495 yearly
Surface facilities	930 total
Off-site requirements	1,190 to 1,440 total

*Upper estimate is for surface disposal of all processed shale. Lower estimate is for underground return of 60% of processed shale.

Water requirements were estimated using a 50,000 barrel a day underground mine and a 100,000 barrel a day surface mine. A production level of 55,000 barrels a day would require about 55,000 to 85,000 acre-feet per year for surface mining or underground mining. In-situ processing would reduce water requirements by about two thirds. Over half of the water required would be used for processed shale disposal by wetting and compacting.

The level of production needed to replace the proposed sale, 331,000 to 536,000 barrels daily, may exceed the capacity of the developing oil shale industry. The National Petroleum Council estimates production in 1980 at 150,000 barrels a day in the most optimistic case. The Interior Department has projected that oil shale production by 1980 could reach 400,000 bbls./day. Given the projected growth of oil shale capacity it is not likely that shale oil could replace the expected MAFLA oil and gas.

B. Synthetic Natural Gas and Oil

TECHNOLOGICAL PROCESSES

Through hydrogenation processes, it is possible to convert coal to various hydrocarbon liquid and gaseous substitutes for natural gas and oil. Considerable research and development has been done and continues in the Federal Government and private industry. While many individual units for commercial gas processes have been tested, synthetic gas has not yet been proved economical in the United States, and no commercial coal-to-liquid conversion plants exist in this country today. A typical coal-gasification process includes:

1. Pretreatment of coal (for sizing, drying)
2. Gasification
3. Char removal
4. Shift conversion to balance $CO\text{-}H_2$ (carbon monoxide and hydrogen) ratio for further reactions
5. Acid-gas removal and sulfur recovery
6. Methanation to convert CO and H_2 to CH_4
7. Drying

Different processes omit some of these steps and add others not listed. The gasification step is highly exothermic. The basic difference among processes is found in the ways in which this heat energy is supplied.

There are three types of systems for production of SNG:

1. Fixed bed units which require pretreatment of caking coals. The Lurgi process is the best example.

2. Fluid bed units which may or may not require pretreatment of caking coals. Some examples are the HYGAS process, the CO_2 acceptor process and the Synthane process.

3. Entrained bed units which do not require pretreatment of caking coals. An example is the BI-GAS process.

Figures IV-5 thru IV-11 show different coal gasification processes.

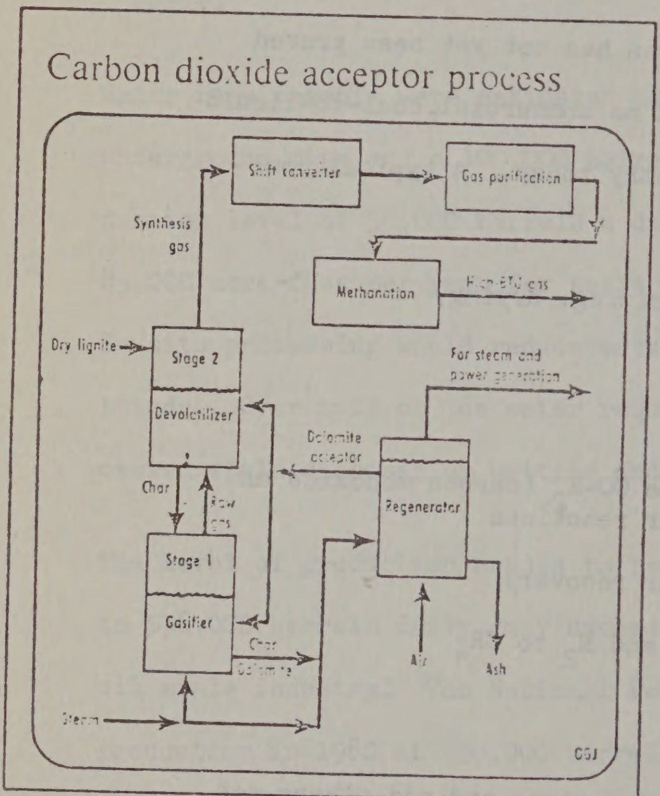


Figure IV-5

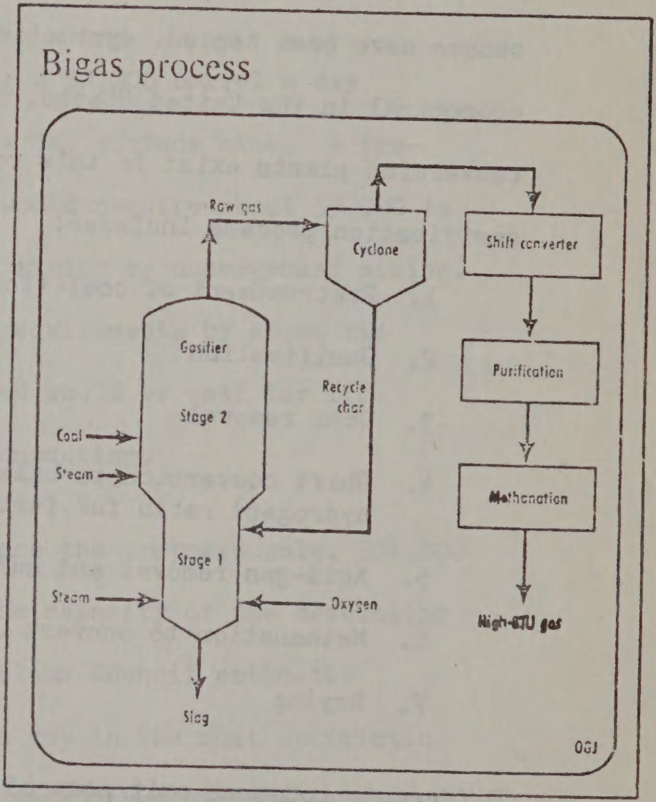


Figure IV-6

Source: D. C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare," The Oil and Gas Journal (Feb. 5, 1973), pp. 68-70.

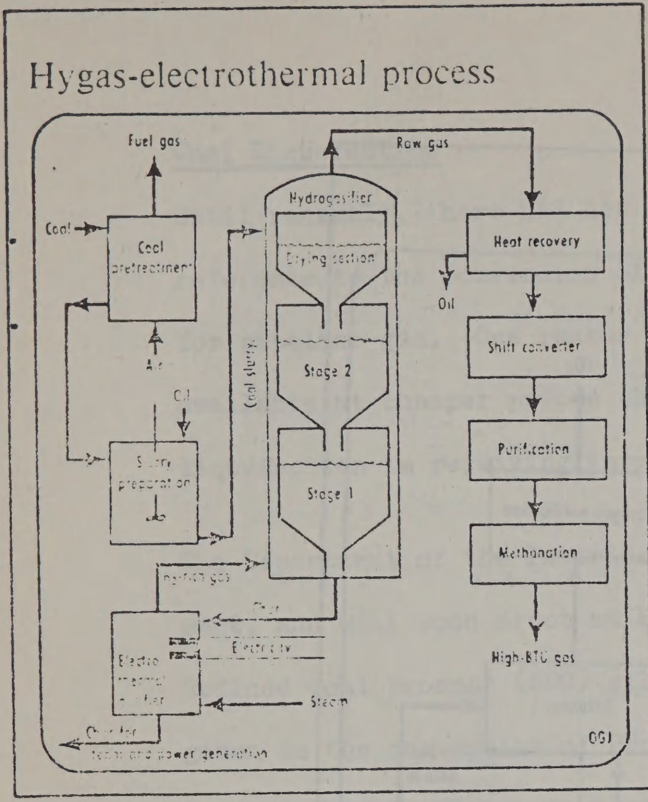


Figure IV-7

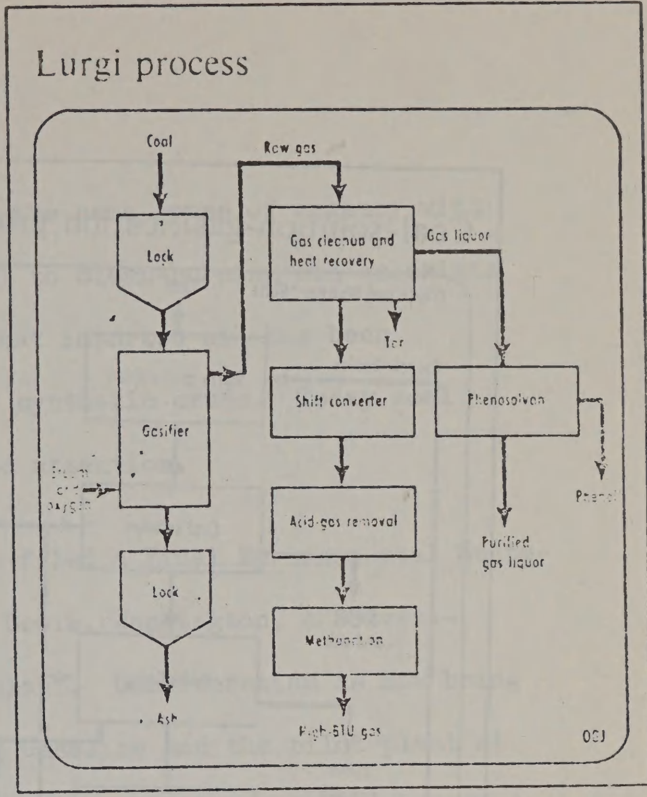


Figure IV-8

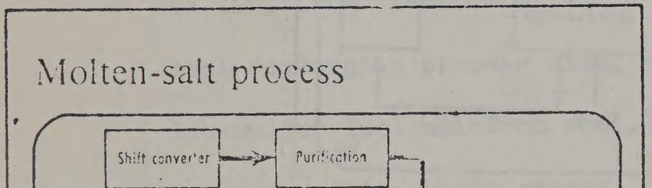


Figure IV-9

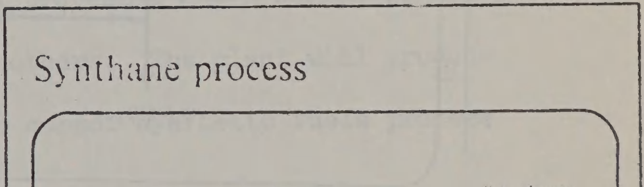


Figure IV-10

Source: D. C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare," The Oil and Gas Journal (Feb. 5, 1973), pp. 68-70.

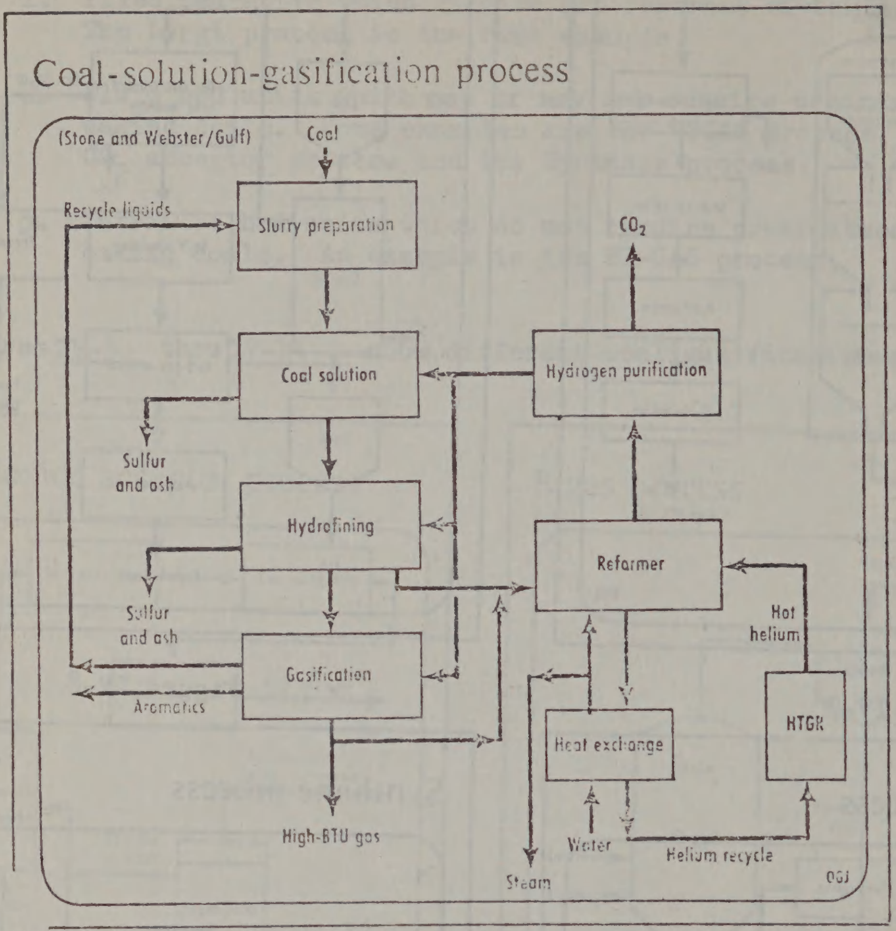


Figure IV-11

Source: D. C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare," The Oil and Gas Journal (Feb. 5, 1973), pp. 68-70.

Coal Liquefaction

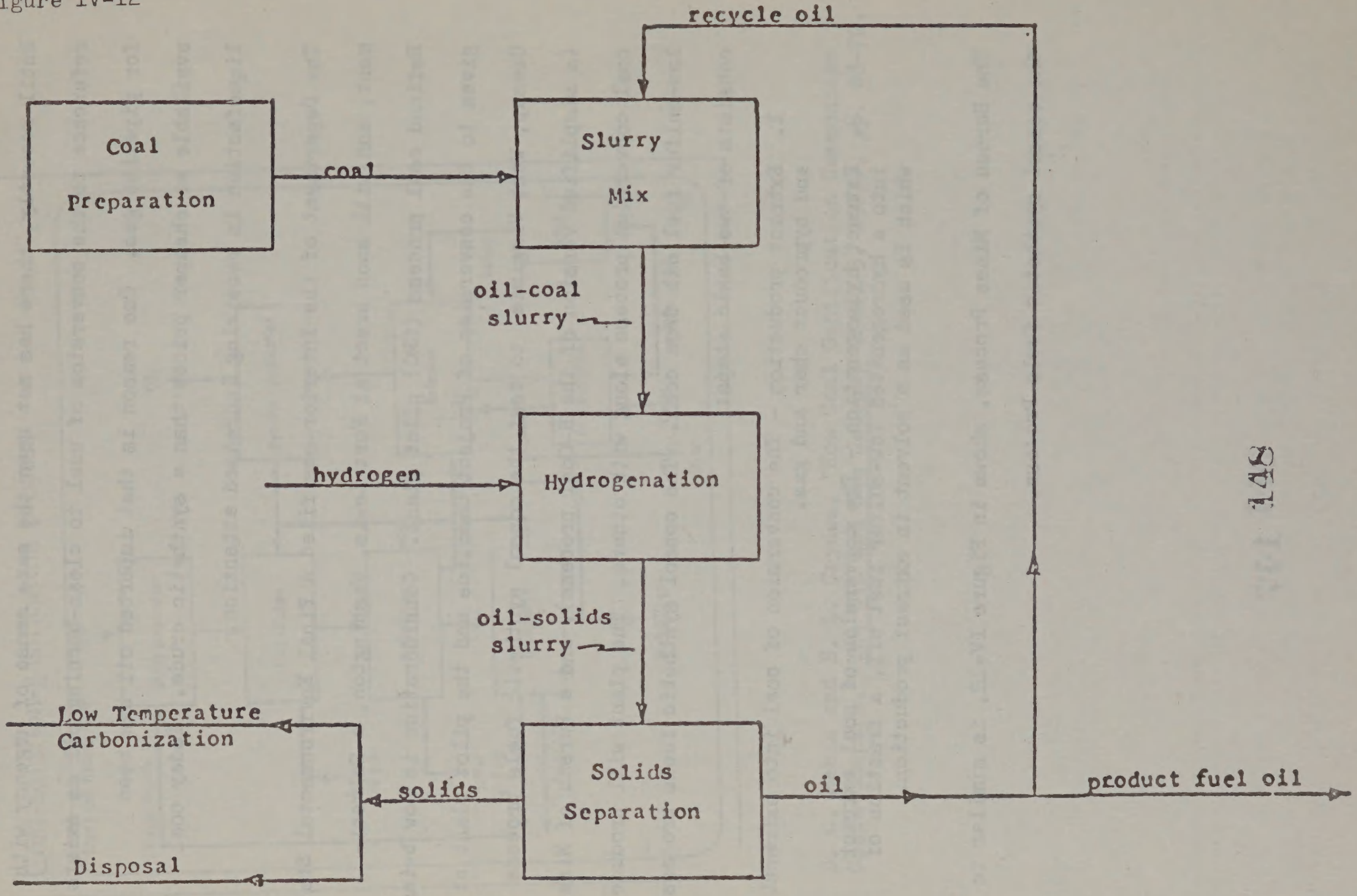
Until recently, there has not been the same sense of urgency with reference to the conversion of coal to clean-burning oil as exists for pipeline gas. One reason is that imported oil has been available at cheaper prices than a synthetic crude. Today coal liquefaction is receiving increased attention.

The Department of the Interior has filed a Final Environmental Statement, and will soon erect at Fort Lewis, Washington, a Solvent-Refined coal process (SRC) pilot plant. Consideration is now being given to the conversion of Project Gasoline and the pilot plant at Cresap, West Virginia, to test the consol synthetic fuels process (a simplified version of the H-Coal process), and a Bureau of Mines coal conversion process along with others. The plant will produce low-sulfur fuel oil from coal. The consol synthetic fuels process consists of two basic steps:

1. Extract production - The conversion of coal into extract and byproduct char and gas.
2. Extract hydrogenation - The conversion of coal extract into a hydrogenated low-sulfur fuel oil, a fraction of which is used as a solvent in extract production.

The Bureau of Mines Process, shown in Figure IV-12, is similar to the consol synthetic fuels Process.

Figure IV-12



Source: Draft Environmental Statement, Proposed Process and Equipment Revisions to the Synthetic Fuels Process Pilot Plant, Cresap, West Virginia - Office of Coal Research, Dept. of Interior, August, 1972.

BUREAU OF MINES PROCESS
Low-Sulfur Fuel Oil

Natural gas can also be synthesized from petroleum. Such gas has been produced commercially in Europe and some 40 plants are in the planning stage for the United States. Feedstocks used range from naptha and other lighter hydrocarbons to crude oil. While oil gasification does not add to overall energy supplies, it is one of the most promising short-term techniques of increasing gas supply with few environmental problems. Processes under consideration include:

1. Thermal cracking in steam.
2. Thermal cracking in a hydrogen-rich atmosphere.
3. Catalytic cracking in steam.
4. Partial oxidation.

Currently, much attention is being given to the catalytic rich process, developed by the British Gas Council. Called the CRG (Catalytic Rich Gas) process, it can gasify a wide variety of hydrocarbon feedstocks, though attention now is concentrated on naptha feedstocks. The CRG process includes desulphurization of feedstocks, methanation and purification to a gas with a heating value of 998 btu per cubic foot.

Desulphurization of the feedstock is accomplished by mixing the feed with hydrogen-rich gas, vaporization, and treatment with nickel-molybdate and zinc oxide catalyst. If a high sulphur content feedstock is used, a hydrodesulphurization step could be employed.

RESOURCE BASE

The resource base and availability of coal and petroleum feedstocks is discussed in sections on each of these fossil-fuels. One 250 billion Btu per day coal gasification plant will require about six million tons of coal annually. Although coal resources are adequate for many years to come, the availability of large amounts of coal for gasification may be a constraint on the development of a gasification industry.

The availability of light hydrocarbons and refining capacity to produce feedstocks for SNG is questionable. About 20 to 25 thousand barrels of hydrocarbon feedstock will be required to produce 100 million cubic feet of SNG.

ECONOMIC CONSIDERATIONS

Coal gasification technology has not yet been fully developed and most processes have not advanced beyond the pilot plant stage. The CO_2 Acceptor process and HYGAS process are currently at pilot plant stage with partial operational tests on certain units. The Bigas and synthane processes are at pilot plant construction stage. The above three along with the Lurgi process are the most advanced in development among all coal gasification methods. Table IV-4 shows the status of various high Btu coal gasification processes and projects as of December 1972, with updates and information on new projects as of April 1973.

Table IV-4

SUMMARY OF HIGH BTU COAL GASIFICATION PROCESSES AND PROJECTS 1/ AS OF DECEMBER 1972

Name of Process	Owner(s) or Contractor and Site	Description of Process	Coal			Status and Funding
			Type	Consumption, ton/day	Plant Output Million cf/day	
Lurgi Pressure Gasification (Lurgi Gesellschaft fur Warme und Chemo nik m.b.H.)	El Paso Natural Gas Co. (Four Corners Area, New Mexico)	A bed of crushed coal is introduced to the gasifier vessel through lock hoppers and travels downward as a moving bed. The process operates at pressures up to 450 psi. Steam and oxygen are introduced through a revolving steam-cooled grate which also removes ash at the bottom of the gasifier. The hydrogen-rich gas passes up through the coal bed, producing some methane by hydrogenation of coal. The product gas is purified and methanated to produce 972 Btu/SCF gas.	limited to non-caking coals	26,600	250	El Paso has made application to the FPC for authorization to construct and operate the Burnham Coal Gasification Complex on the Navajo Indian Reservation. Capital costs are $353.2 million for the gasification plant and $65.3 million for the associated mine. Initial gas production is scheduled for June 1976, and the estimated 1977 cost of gas at the plant outlet is $1.20/MCF.

1/ American Gas Association, "Gas Supply Review", Vol. I, Nos. 3 and 7, December 15, 1972 and April 15, 1973.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type of coal	Status and Funding
Lurgi Pressure Gasification	Texas Eastern Transmission Corp., Pacific Lighting Corp., Utah International, Inc. (Four Corners Area, New Mexico)	Same as above Plant Output 250 million cf/day	limited to non-caking coals Consumption of coal - 20,000 tons/day	Feasibility study contract has been awarded to the Fluor Corp. Plant cost is estimated at over $300 million. Plant operation could start in 1976.
Lurgi Pressure Gasification	Panhandle Eastern Pipe Line Co. and Peabody Coal Co. (Illinois)	Same as above	limited to non-caking coals	Feasibility study contract has been awarded to M. W. Kellogg and American Lurgi Corp.
Lurgi Pressure Gasification	Conoco Methanation Co. and Scottish Gas Board (Westfield, Scotland)	Methanation of purified low-Btu product gas from a Lurgi pressure gasifier to demonstrate the commercial feasibility of the combination of Lurgi gasification and methanation to produce a 950+ Btu/SCF gas.	subbituminous Plant output 250 million cf/day	Conoco Methanation Co. will design and construct facilities to carry out a 1-yr. test at a total cost of $6 million. Eleven U.S. companies are sponsoring the test which is scheduled to begin in mid-1973. The construction contractor is Woodall-Duckham, Ltd.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
Lurgi Pressure Gasification	South African Coal, Oil, and Gas Corp., and Lurgi (Sasolburg, South Africa)	Methanation of the product gas from a Lurgi gasifier to produce 950^+ Btu/SCF gas.	-	An experimental program to demonstrate commercial feasibility of methanation. A slip-stream from the SASOL plant will be used as feed to the methanator.
COGAS	COGAS Development Co. (FMC Corp., Panhandle Eastern Pipe Line Co., and Tenneco, Inc.) (Princeton, New Jersey)	Coal is charged to a series of fluidized-bed reactors with increasing stage temperatures to pyrolyze the coal and drive off volatile fractions in each stage. After separation of the oils and gas produced in the initial processing, the residual char is reacted with steam and air to produce a synthesis gas which is purified and methanated to a 950^+ Btu/SCF gas. The operating pressure is 50 psig. The oil by-product is hydrotreated to make a synthetic crude oil.	subbituminous and bituminous	The first stage of the COGAS Process is based on results from the COED pilot plant in Princeton, N.J., which was designed to produce oil, char, and a relatively small amount of gas. The COED pilot plant was funded by OCR and completed in 1970 at a cost of $4.5 million COGAS Development Company will invest an initial $5 million for a pilot plant for an 18-24 month process evaluation.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
HYGAS	Institute of Gas Technology (Chicago, Illinois)	Ground, dried coal is pretreated with air, slurried with by-product oil, and fed to a two-stage fluidized bed hydrogasifier operating at 1000-1500 psia; hydrogen-rich gas for the reaction can be furnished by processes using electric energy or oxygen, or by the steam-iron process. Gas from the reactor is purified and methanated to produce 950+ Btu/cu. ft. gas.	all U.S. coal types Consumption 75 tons/day (pilot plant) Plant Output 1.5 million cf/day	Pilot plant in operation. Preliminary demonstration plant design complete. Original cost of pilot plant was approximately $9.5 million.
Koppers-Totzek	Koppers Company	Raw coal is dried, ground and charged to a gasifier by a screw conveyor with a mixing head in which oxygen and steam are added to the coal fines. The reactor operates at atomspheric pressure and at 2700°F. The product gas, mostly hydrogen and carbon monoxide, can be methanated to produce 950+ Btu/SCF gas. Sixteen low-Btu plants are in operation in other countries, primarily to make synthesis gas for ammonia production.	all U.S. coal types	Process is being offered in U.S. and Canada under a general license from Heinuch Koppers G.m.g.H., Essen, West Germany.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
ATGAS	Applied Technology Corp.	Coal is injected into a molten iron bath where steam and oxygen react with the carbon to produce hydrogen and carbon monoxide. The gases are then methanated to produce 950^+ Btu/SCF gas.	all U.S. coal types	EPA has added $222,000 to its July contract of $620,000 for work on the high Btu gas process. A.G.A. has awarded the company $282,000 for developing a pre-pilot plant to demonstrate the process.
Union Carbide	Chemical Construction Corp. (Chemico) has been licensed by Union Carbide to use coal gasification technology developed by Union Carbide	Coal is crushed and fed to a gasifier as a dry solid or water slurry. The coal is heated in the presence of steam by direct contact with hot ash agglomerates generated by the combustion process, producing a product containing carbon monoxide, hydrogen and about 10% methane.	-	-
	Coteau Properties (wholly owned subsidiary of North American Coal Corp) and Michigan Wisconsin Pipe Line Co.	-	-	A 15 yr. option on lignite reserves to convert to synthetic gas, not before 1980's.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
-	Colorado Interstate Gas Co. and Westmoreland Resources	-	-	A 10-yr. option on coal reserves. Feasibility of coal gasification plant will be studied.
-	The Columbia Gas System, Inc.	-	-	Core drilling program in West Virginia to identify possible sites for coal gasification facilities. 293 million tons of recoverable coal reserves have been proved on part of land on which the company has coal rights.
-	Texas Gas Transmission Corp. and Consolidation Coal Co.	-	-	Texas Gas Transmission Corp. has acquired one-half interest in a large block of Illinois Basin coal reserves controlled by Consolidation Coal Co. The largest parcel will be held for 10 years for possible use in a coal gasification project.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
-	Eastern Gas & Fuel Associates and Texas Eastern Transmission Corp.	-	-	The companies have acquired coal mining and prospecting rights to about 40,000 acres of federal and state leases in northwestern New Mexico. If the reserves are developed, Eastern Gas would conduct the mining and Texas Eastern would build and operate the gasification plant.
CO_2 Acceptor	Consolidation Coal Company (pilot plant constructed and operated by Stearns-Roger Corp.) (Rapid City, S.D.)	Coal is charged to a devolatilizer and is contacted at 300 psia with hydrogen-rich gas from a gasifier vessel. Lime or dolomite (the "Acceptor") is added to both vessels, where it reacts with carbon dioxide. "Acceptor" regeneration and ash removal is carried out in an air-blown regenerator vessel where spent char is combusted. The product gas can be purified and methanated to produce a 950^+ Btu/SCF gas.	lignite and subbituminous Consumption 40 tons/day (pilot plant) Plant Output up to 2 million cf/day (no heating value apecified)	Pilot plant undergoing start-up. A methanation stage is not incorporated, but may be added at a later date. The original pilot plant cost was about $9.3 million.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
BIGAS	Bituminous Coal Research, Inc. (Homer City, Pa.)	Coal is introduced into a reactor where it is contacted and partially gasified with hydrogen-rich gas produced in the lower section of the reactor by the slagging gasification of recycle char with oxygen and steam. The pressure of operation is 1000 psia. The product gas can be purified and menthanated to produce 950$^+$ Btu/SCF gas.	all U.S. coal types Consumption 120 tons/day (pilot plant) Plant Output 2-3 million cf/day	Preliminary pilot plant design complete. Construction contract has been awarded to Stearns-Roger, Inc. Plant cost will be about $18 million and construction will take 18-24 months.
Synthane	U.S. Bureau of Mines	Coal is introduced into a single reactor which incorporates three processing steps; a free-fall oxygen-steam pretreatment zone, a dense fluid bed carbonizer, and a dilute fluid bed gasifier. Hydrogen-rich gas for the reaction is produced by use of oxygen in the reactor. The process operates at 500-1000 psia. The product gas can be purified and methanated to produce 950$^+$ Btu/SCF gas.	all U.S. coal types Consumption 70 tons/day (pilot plant) Output of plant 1.4 million cf/day	Pilot plant design completed. Estimated cost is $10 million. Plant will be completed in December 1973.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
Kellogg Molten Salt Process	M.W. Kellogg Company	In the latest version of this process oxygen, steam and coal are injected into a high - purity alumina reaction vessel where molten sodium carbonate catalyzes the coal for complete gasification. The product gas can be purified and methanated to produce 950^+ Btu/SCF gas.	all U.S. coal types	OCR funded a bench scale program from 1964-1967. Total expenditures were $1.7 million. Major difficulties were experienced with materials of construction. OCR ceased sponsorship because of this problem, budgetary restrictions and assignment of higher priorities to other coal gasification processes. M. W. Kellogg has carried out additional development work since 1967, but support has not yet been obtained for construction of a large scale pilot plant.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
None	Garrett Research and Development Co. (sponsored by Colorado Interstate Gas Co.)	Coal is introduced into a simple reactor at atmospheric pressure where gas is produced by rapid devolatilization of coal. Large amounts of excess char are produced.	all U.S. coal types	Early stage of development. Being tested in small pilot plant in La Verne, California.
None	Gulf General Atomic and Stone & Webster	Coal is dissolved and the solution is hydrocracked and reacted non-catalytically with hydrogen to produce gas which is purified and methanated to 950^+ Btu/SCF gas.	all U.S. coal types	Feasibility studies being made.

Table IV-4 (cont'd)

Updated Information as of April 1973

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
Lurgi Pressure Gasification (Updated)	Texas Eastern Transmission Corp., Pacific Lighting Corp., Utah International Inc. (Four Corners area, New Mexico)	A bed of crushed coal is introduced to the gasifier vessel through lock hoppers and travels downward as a moving bed. The process operates at pressures up to 450 psi. Steam and oxygen are introduced through a revolving steam-cooled grate which also removes ash at the bottom of the gasifier. The hydrogen-rich gas passes up through the coal bed, producing some methane by hydrogenation of coal. The product gas is purified and methanated to produce 972 Btu/SCF gas.	Limited to non-caking coals Consumption 26,300 tons/day Plant Output 250 million cf/day	Texas Eastern and Pacific Lighting have made application to the FPC for authorization to construct and operate a $405.9 million coal gasification plant on the Navajo Indian Reservation near Farmington, N.M. Utah International will supply the coal and water. Plant operation is scheduled for 1976.
Lurgi Pressure Gasification (New Project)	El Paso Natural Gas Co. (Four Corners area, New Mexico)	Same as above.	Limited to non-caking coals Consumption 765 tons/day Plant Output 50 million cf/day of raw synthesis gas	A single Lurgi gasifier will be installed to test improvements in the process. Goals are operation at 20% above design capacity and 30% above design pressure, gasifier mechanical improvements, coal fines gasification,

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
				and improved pollution control. Capital investment will be $14.1 million; first-year operating cost will be $4.5 million. Completion and operation is scheduled for April 1974.
(New Project)	Battelle Columbus Laboratories (West Jefferson, Ohio)	Coal is reacted with oxygen and steam in a fluidized-bed gasifier at pressures up to 100 psi to produce a synthesis gas suitable for conversion to high-Btu pipeline gas by methanation.	Bituminous Plant Output 0.8 million cf/day of synthesis gas	Battelle has been granted a 30-month, $4.1 million contract under the joint OCR/A.G.A. program.
(New Project)	Chem Systems Inc. (Hackensack, N.J.)	A menthanation process to convert coal-derived synthesis gas to high-Btu pipeline gas.	-	Chem Systems has been awarded a 30-month, $1.9 million contract under the joint OCR/A.G.A. program.
(Update)	Coteau Properties (wholly owned subsidiary of North American Coal Corp) and Michigan Wisconsin Pipe Line Co.	-	Lignite	Original dedication of 1.5 billion tons of North Dakota lignite for 15 years has been expanded to a total of 2.7 billion tons, and term of agreement has been extended to December 1, 1993.

Table IV-4 (cont'd)

Name of Process	Owner(s) or Contractor and Site	Description of Process	Type	Status and Funding
(New Project)	Northern Natural Gas Co. and Cities Service Gas Co. (Powder River Basin, Montana)	-	- Plant Output 250 million cf/day (initial plant)	Northern Natural and Cities Service are considering construction of four 250 million CF/day coal gasification plants. Peabody Coal has agreed to supply about 500 million tons of coal, and the gas companies are negotiating for another like amount. $10 million will be spent for preliminary development through 1975. Construction of the first plant could start in 1976, with operation in 1979.
(New Project)	Natural Gas Pipeline Co. of America (Dunn County, N.D.)	-	Lignite	Rights to 2 billion tons of lignite have been obtained from Star Drilling Inc. The lignite will be reserved for possible future use in a coal gasification project.

The commercially available Lurgi coal gasification process is employed in several plants in West Germany and other parts of West Europe to produce low-Btu value gas (400-450 Btu/cf). Catalytic methanation, required to achieve pipeline quality gas of 1000 Btu/cf, has not yet been commercially demonstrated. The first commercial-scale test of production of pipeline coal gas will be undertaken by Conoco Methanation Company, which will add methanation facilities to the Scottish Gas Board's Westfield coal gasification plant by mid 1973. This plant uses the Lurgi process. The first commercial coal gasification plant to produce pipeline quality gas, will use the Lurgi process and will be built near Four Corners, New Mexico. The 250 million cubic feet per day plant, to cost about $250 million, is expected to be in operation by 1976. The first operational Lurgi gasifier in the U. S. will be completed by El Paso Natural Gas Company in April 1974. The gasifer, also in the Four Corners area, will cost $14.1 million and have no methanation step.

In August 1971, the Department of the Interior and the American Gas Association signed an agreement for an accelerated program for coal gasification which will cost about $120 million over four years. Three pilot plants (HIGAS, BI Gas, and CO_2 Acceptor) will be in operation under the program. In each of the plants a unique gasification method will be tried in conjunction with different systems of gas cleanup and methanation so that a final process, combining the best features of the individual processes, can be chosen.

Part of the funds will go to the Applied Technology Corp. for development of the ATGAS process which uses a unique molten-iron gasification technique with steam and oxygen at low pressure. The product is a gas suitable for conversion to SNG. The process, which can gasify coal within a very large range of physical properties and sulphur content, enables economical use of coals for which there are few other markets. Construction and operation of a pilot plant is planned. Also under the program, Columbus Laboratories of the Battelle Memorial Institute is working on development of a coal-gasification fluidized-bed coal burner to provide the heat for steam gasification of coal. A pilot plant will be operated to obtain performance data for assessment of the commercial potential of the process.

An important part of the program is the development of the BI-GAS process (see Figure IV-6) to produce pipeline quality gas. The core of this process is the two-stage gasifier which uses pulverized coal in entrained flow. A pilot plant in Homer City, Pennsylvania is presently under construction and scheduled for start-up in 1974. Advantages of this process are 1) a high yield of methane obtained directly from coal, with minimal subsequent processing of the product gas, 2) no tars and oil are formed in the gasification process, 3) all the feed fuel is consumed in the process, and 4) the two-stage gasifier is relatively simple in design and amenable to scale-up to any size.

The economics of coal gasification will be greatly influenced by finalized process configurations. Intense interest has been shown by electric utilities in development of integrated coal gasification electricity generation systems using low Btu gas. Research also centers on processes whose major end product is pipeline quality gas with minor credits for by-products such as sulfur and phenol. Further advances may result in an optimized process which produces not only pipeline gas, but also liquid and solid hydrocarbon fuels and electric power.

Unitl further demonstration plant design and operation, estimates of capital requirements are speculative. In early 1972, FPC estimated that capital expenditures to develop gasification plants and supporting coal mines for supplying one trillion cubic feet of SNG annually for a period of 20 years would be $2.4 billion. Capital expenditure for a 250 million cu. ft. per day gasification plant is estimated at about $175 million. 1/ More recent estimates for this size coal gasification plant are from $250 to $300 million, which raise the capital expense of annual capacity of one trillion cubic feet to about $3.0 to $3.6 billion. The National Academy of Engineering, in a contract study for the Department of Interior, Office of Coal Research, estimated a $3.4 billion capital investment for 12 coal gasification plants to produce one trillion cu. ft. of gas yearly.

1/ Federal Power Commission, Bureau of National Gas Supply and Demand, 1971-1990, staff Report No. 2, Washington, D. C., Feb. 1972, p. 90.

An evaluation of the economics of different coal gasification processes is shown in Tables IV-5 and IV-6. Costs are based on plant capacity of 250 million cu. ft. daily.

Capital requirements for SNG plants using petroleum feedstocks will be about $800 million to $ 1 billion. Prices for announced projects are from $1.00 to $1.60 per Mcf.

Economics of processes, coal at 25¢/MMBTU

	CO₂ acceptor			Bigas			Hygas-electrothermal			Molten salt			Lurgi		
Rate of return	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%
Total fixed investment, $MM	103.31	103.31	103.31	170.00	170.00	170.00	156.12	156.12	156.12	159.60	159.60	159.60	286.00	286.00	286.00
Total working capital, $MM	8.73	9.05	9.27	8.61	9.06	9.52	9.27	9.69	10.11	8.68	9.11	9.54	10.30	11.02	11.77
Total capital investment, $MM	111.04	112.36	112.58	178.61	179.05	179.52	165.39	165.81	166.23	168.28	168.71	169.14	296.30	297.02	297.77
Net operating expenses per year, $MM	49.84	49.84	49.84	56.16	56.16	56.16	58.70	58.70	58.70	53.46	53.46	53.46	69.40	69.40	69.40
Annual average revenue requirement, $MM	57.34	60.71	63.23	67.46	72.71	77.97	69.20	74.05	79.02	64.12	69.05	74.04	87.72	96.23	104.87
20-year average gas selling price, ¢/MMBTU	69.4	73.5	76.5	82.4	88.9	95.4	83.4	89.3	95.3	81.1	87.4	93.6	109.1	119.6	130.4

Table IV-5

Table IV-6

Economics of processes, coal at 35¢/MMBTU

	CO₂ acceptor			Bigas			Hygas-electrothermal			Molten salt			Lurgi		
Rate of return	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%	9%	12%	15%
Total fixed investment, $MM	103.31	103.31	103.31	170.00	170.00	170.00	156.12	156.12	156.12	159.60	159.60	159.60	286.00	286.00	286.00
Total working capital, $MM	11.36	11.68	12.00	10.81	11.28	11.77	11.79	12.47	12.84	10.74	11.19	11.64	12.33	13.07	13.82
Total capital investment, $MM	114.67	114.99	115.31	180.81	181.28	181.77	167.91	168.59	168.96	170.34	170.79	171.24	298.33	299.07	299.82
Net operating expenses per year, $MM	64.02	64.02	64.02	69.81	69.81	69.81	74.30	74.30	74.30	65.54	65.54	65.54	81.11	81.11	81.11
Annual average revenue requirement, $MM	71.99	75.34	78.33	80.41	85.71	91.13	85.23	90.44	95.45	76.44	81.53	86.65	99.80	108.43	117.14
20-year average gas selling price, ¢/MMBTU	87.0	91.2	95.5	98.3	104.9	111.7	100.2	109.0	115.0	95.5	103.1	108.6	124.1	134.8	145.6

Source: D. C. Mehta and B. L. Crynes, "How Coal Gasification Commonbase Costs Compare, "The Oil and Gas Journal" (Jan. [illegible], 1975), 70-71.

The Department of the Interior 1/ gives the following forecasts for production of synthetic gas:

Year	Total Gas Produced		Energy Inputs	
	bil. cu. ft.	Tril. btu.	Coal mil. tons	Petroleum mil. bbl.
1980	700	700	19	84
1985	2,000	2,000	86	128
2000	5,500	5,500	308	105

Table IV-7

Factors that will influence the rate of growth of a coal gasification industry are the availability of coal and petroleum feedstocks, the development of needed mining capacity (including availability of manpower for mining), availability of capital, and availability of refining capacity to provide light hydrocarbon for feedstocks.

The National Petroleum Council has estimated SNG production from petroleum feestocks at 0.6 trillion cf in 1975 and 1.3 tcf in 1980, and 1985. These figures reflect the assumptions that one third of announced plants will be operating by 1975 and one half of plants scheduled to be in production in 1980 and 1985 will be completed on schedule. These assumptions show the retarding effects of Government regulations, import restrictions, and siting and administrative delays.

1/ United States Energy Through the Year 2000, U. S. Department of the Interior, December 1972, p. 31.

ENVIRONMENTAL IMPACT

Like natural gas, the product of coal gasification or liquefaction (i.e., synthetic natural gas or coal oil) are clean-burning fuels as a result of the pollution control feature integral to the manufacturing process.

The first environmental obstacle common to all ventures using coal for energy is coal retrieval. In addition, coal gasification and liquefaction processes must contend with water consumption and contamination, air pollution from sulphur components and particulate matter, and possible noise and site pollution.

Impact on Air Quality

Plant operation, consisting of handling and transporting the coal to the process and converting the coal to gas and/or, will involve very large quantities of devolatilized coal, called char, which will be burned in boilers to generate process steam and power, or gasified to make process hydrogen. Major emissions that must be controlled are sulphur and nitrogen oxides, and bottom ash and slag, and fly-ash from the plants generating process steam and power. Since coal-conversion plants are located next to strip mines, ash and slag from the process is returned to the open cuts, and the ground is restored in accordance with environmental considerations. The technology for controlling sulphur and nitrogen oxides from such plants is under development.

To illustrate the order of magnitude of the major emissions that would have to be handled from a commercial coal-to-pipeline gas plant, the FPC's National Gas Survey 1/ gave the following estimates, based on a plant producing 250 million standard cubic feet per day of pipeline gas 2/ from coal with 3.7 percent sulphur:

Table IV-8	long tons per day
Sulphur (mainly as hydrogen sulphide)	300-450
Ammonia	100-150
Phenols	10-70
Benzene	50-300
Oil and tars	trace to 400
Ash (based on coal with 10% ash)	1500

1/ Federal Power Commission, Final Report, Supply-Technical Advisory Task Force - Synthetic Gas - Coal, Chapter X, p. X-2. Prepared by the Synthetic Gas - Coal Task Force for the Supply - Technical Advisory Committee, National Gas Survey, May, 1973.

2/ This size SNG plant produces the equivalent of 40,000 barrels per day of crude petroleum.

The environmental impacts of SNG plants using naptha feedstocks are expected to be less than those comparable coal-based synthesis plants, because they would be free of ash and char, and sulphur oxides and particulates discharge problems.

Impacts on Water Quality

Plant operation involves very large quantities of water for cooling and scrubbing gases, perhaps as high as 30 million gallons per day for a completely water cooled plant producing 250 million cubic feet of SNG per day. 1/ The discharge of contaminants such as phenols, cresols, benzene, oil, and tars must be controlled through use of purification systems integrated into the facility or through re-circulation of waste water to extinction. Process waste solids such as spent dolomite, in the case of the CO_2 Acceptor process, may present problems of surface water contamination.

Impact on Land Quality

Waste solids such as char, granulated extract, and powered sulfur must be disposed of. Much of the solid waste will be used as fill in trenches left by surface mining operations prior to recontouring of the land to match its original surroundings.

1/ Jane Stein, "Coal Is Cheap, Filthy, Needed", Smithsonian, Feb. 1972, p. 25. A water requirement of 8 to 9 million gallons daily for a partially air-cooled plant is given in Coal Age, mid-April 1973, "Challenges and Opportunities of Western Coal", p. 42.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

This alternative would involve a combination of synthetic oil and gas with a total value or 1.917 to 3.106 trillion Btu's, the energy equivalent of the oil and gas expected from the proposed MAFLA sale. The mix could range from all synthetic oil, 331,000 to 536,000 barrels a day, to all synthetic gas, 1.55 to 2.54 billion cf a day.

Complete substitution by coal gasification would require 8 to 13 250 billion Btu's per day coal gasification plants, 50 to 82 million tons of coal per year, and 17 to 28 coal mines. At an estimated $250 million for each plant, these plants would cost $2.0 to $3.25 billion.

Projections of the Interior Department for the development of the coal gasification industry estimate yearly production of coal gas by 1980 at 700 billion cf. To completely replace the expected MAFLA oil and gas production would call for 566 to 928 billion cubic feet a year of coal gas. In view of the present lack of a commercial coal gas industry and the uncertainty of the related economics and technology, the possibility of coal gas serving as an alternative to the projected MAFLA sale depends on the rate of development of the industry. The National Petroleum Council projects 1980 production of SNG from petroleum feedstocks at 1.3 trillion cf. The gas equivalent of the proposed MAFLA sale (566 to 928 billion cf. yearly) represents from 44 percent to 71 percent of the total yearly projected production of SNG. About 193 to 240 thousand barrels of hydrocarbon feedstocks would be required each year to produce 900 billion cf of gas.

5. Hydroelectric Power

TECHNOLOGICAL PROCESSES

Conventional hydroelectric developments convert the energy of natural regulated streamflows falling through heads 1/ created by dams and waterways to produce electric power. Plants are classfied as run-of-river or storage projects, depending on the way in which available streamflow is utilized. In conventional plants, water comes to the plant as a result of natural means.

Pumped storage projects generate electric power by releasing water from an upper to a lower storage pool and then pumping the water back to the upper pool for repeated use. During off-peak hours when project capacity is not required by the system, water is pumped to the upper pool using energy generated by other sources, usually by large modern steam-electric units. A pumped storage project consumes more energy than it generates. Its economic advantage comes from converting low-cost, low-value off-peak energy to high-value peak capacity and energy, and from the highly flexible peaking power it makes available. Pumped storage projects may be designed exclusively as pumped storage or may be included in the design of a conventional hydroelectric installation.

1/ Head refers to the height of fall for use in calculating water pressure per unit area.

RESOURCE BASE

The total conventional hydroelectric power potential of the 48 contiguous states at both developed and undeveloped sites is estimated to be about 146,000 MW of capacity able to produce about 530 million megawatt hours of electric energy annually. Of this total, 94,000 megawatts and 272 million megawatt hours remained undeveloped as of January, 1972. Although most available sites for economical production of hydroelectric energy have been developed, some additional capacity will be provided by new sites or expansion of existing plants. Use of hydroelectric power to service peak loads enhances project benefits, permitting consideration of possibilities which formerly were marginal or uneconomic under higher capacity factor standards. Multipurpose benefits such as recreation, water supply, fish and wildlife enhancement, and flood control justify projects that would otherwise be uneconomic for a single purpose.

The availability of pumped storage sites largely depends on topography which allows development of a high head between two reservoirs in the same area. In many parts of the country, there are virtually unlimited physical opportunities for developing pumped storage projects. However, only a limited number of sites have been investigated.

ECONOMIC CONSIDERATIONS

The investment in hydroelectric projects per kilowatt of installed capacity varies greatly according to the type of project, size and location, the cost of lands required, and the cost of relocation of highways, building, railroads, and other improvements. The capital costs of powerhouse and equipment per unit of installed capacity decrease with an increase in head. The unit cost at a particular site is less if large capacity units are installed rather than more units of smaller size.

Excluding pumped storage, average investment costs per kilowatt are substantially higher for hydroelectric plants than for thermal-electric plants. Capital costs of hydroelectric plants range from $200 to $400 per kilowatt of installed capacity. Total capital costs of conventional plants built in the 60's ranged from about $40 million for capacity of about 200MW to $200 million for capacity of about 700MW. On the other hand, operating expenses are much lower, largely because no fuel is required and other operating and maintenance costs are less.

Pumped storage plants have low capital costs ranging from $100 to $150 per kilowatt installed, and low maintenance costs. Total capital costs are from $30 million and up.

Present and Projected Supply-Demand

The Department of Interior 1/ gives the following projection for hydropower development that includes both hydro and pumped storage plants.

Table V-1

Present and Projected Hydropower and Total Electric Utility Capacity

	Installed Capacity (MW)			Net Generation (billion KW hrs)	
Year	Total Electric Utility	Hydropower	Hydropower as a % of total electric utility capacity	Total Electric Utility	Hydropower
1971	367,395	55,898	15.2%	1,614	266
1975	480,000	80,000	16.7	2,130	350
1980	660,000	95,000	14.4	3,000	420
1985	915,000	120,000	13.1	4,140	470
2000	1,880,000	200,000	10.6	9,010	700

The Federal Power Commission projects conventional electric generating capacity in the contiguous United States as follows:

1/ United States Energy through the Year 2000, U. S. Dept. of the Interior, December 1972, pg. 26.

Table V-2

Conventional Hydropower, Pumped Storage, and Total Electric Generating Capacity by Region

Year		Total electric generating capacity	conventional hydro capacity	pumped storage capacity
1970	Northeast	64.9	5.8	1.8
	East Central	55.0	1.0	0.1
	Southeast	63.7	9.3	0.1
	West Central	42.6	3.5	0.4
	South Central	48.9	2.3	0.1
	West	64.9	29.7	1.1
	Total contiguous U. S.	340.0	51.6	3.6
1980	Northeast	113	7	9
	East Central	103	2	4
	Southeast	132	11	4
	West Central	82	3	2
	South Central	106	3	3
	West	129	42	5
	Total contiguous U. S.	665	68	27
1990	Northeast	201	7	19
	East Central	186	3	14
	Southeast	255	13	13
	West Central	152	3	4
	South Central	211	4	8
	West	255	52	12
		1,260	82	70

Source: 1970 National Power Survey, Federal Power Commission, Dec. 1971, I-8-28-9. All units are thousands of megawatts.

The predomination of pumped storage over conventional hydropower in new construction can be seen in the percentages below, calculated from the above table.

Year	conventional hydro as percent of total electrical generating capacity	pumped storage as percent of total electrical generating capacity
1970	15.2	1.1
1980	10.0	4.1
1990	6.5	5.6

ENVIRONMENTAL IMPACT

Impact on Air Quality

Construction activity increases the dust in the air. However, operation of the hydroelectric power plant produces no air pollution, radioactivity, nor waste heat.

Impact on Water Quality

Construction often results in temporary increases in stream turbidity. The newly filled reservoir usually has a low dissolved oxygen content. Reservoirs concentrate salt due to evaporation.

Impact on Land Quality

Construction of a hydroelectric dam represents an irretrievable commitment of the land resources beneath the dam and lake. Inundation of the land eliminates wildlife habitat and precludes other uses such as agriculture, mining, and free-flowing river recreation. Some increase in erosion during construction and operation will occur.

Impact on Fish and Wildlife

Fish and wildlife habitat may be significantly changed. The reproductive habitats of anadromous fish may be severely altered by dam construction, unless elaborate provision is made for fish ladders or other means to provide safe fish passage. Significant mortalities of resident and anadromous fish in rivers servicing hydroelectric dams can be cuased by gas-bubble disease resulting from exposure to nitrogen supersaturated water. Nitrogen supersaturation results at a dam when excess river flow must be passed over the spillway.

Survival studies conducted in 1971 indicate that high nitrogen levels in the Columbia and Snake Rivers pose a serious threat to the future of the salmon and steelhead resources of the region. 1/ Under present plans to expand the Columbia Basin hydroelectric system through 1980, the volume of spills at the various projects will be reduced. However, without additional control measures, the reduction in volume of spills will not be great enough to reduce nitrogen supersaturation to levels considered safe for fish during years of average or higher flows.

1/ Power Planning Committee, Pacific Northwest River Basins Commission, Review of Power Planning in the Pacific Northwest, Calendar Year 1971, pp. 71-76, submitted by Idaho State Director, Bureau of Land Management.

The Corps of Engineers is actively engaged in studying and testing several approaches to the solution of the nitrogen problem. Efforts have been concentrated on manipulation of storage, full use of generating units, slotted intake gates, collection and transportation of downstream migrants, and spillway modifications.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

The hydroelectric generating capacity required to substitute for the energy from the oil and gas expected from the proposed MAFLA sale depends on whether the oil and gas is employed in direct end uses (such as oil and gas heating) or in electricity generation. Since direct uses convert oil and gas to energy more efficiently, a larger generating capacity would be required to substitute for this energy.

To substitute for end uses of the MAFLA oil and gas, capacity of from 20,000 to 33,000 megawatts would be needed. To substitute for the electricity which could be generated by the oil and gas, 11,000 to 18,000 megawatt capacity would be needed.

The extent of U. S. conventional hydropower potential east of the Mountain states, the region to be served by the proposed MAFLA sale, is shown below.

Region	Potential Power	Developed Capacity	Undeveloped Capacity
New England	4.8	1.5	3.3
Middle Atlantic	8.6	4.3	4.3
East North Central	2.2	0.9	1.3
East South Central	9.1	5.2	3.9
West North Central	7.0	2.7	4.3
South Atlantic	14.5	5.5	9.0
West South Central	5.1	2.1	3.0
Total	51.3	22.2	29.1

All units are thousands of megawatts.
Source: From "Hydroelectric Power Resources of The United States, Developed, Undeveloped, January 1, 1973," Federal Power Commission, December, 1972.

The feasibility of hydropower as an alternative to the oil and gas expected from the MAFLA sale is restricted by other factors. Hydroelectric power can not be substituted for use of oil and gas in transportation and in industrial processes dependent on unique properties of oil and gas. Land use considerations may preclude development of the few promising potential conventional hydro sites east of the Mountain states. Sites where pumped storage projects may be developed are numerous but have not been systematically inventoried. Furthermore, few dams are built solely for hydroelectric power generation. Irrigation, navigation, municipal and industrial uses, and flood control are frequently more important than and not fully compatible with power production needs. Since hydropower is most often used to service peak loads, other energy sources must be relied on for base power loads.

6. Nuclear Power

TECHNOLOGICAL PROCESSES

One of the most important advances in the electric power industry in the past few decades has been the development of nuclear energy. Nuclear reactors fall under two types: "thermal" or "fast". Thermal reactors, including the light-water reactors, employ moderating materials to slow the neutrons before the majority of fissioning occurs; in fast reactors fission is produced by neutrons of much higher energy levels. The fast reactor offers the possibility of using a much greater portion (estimated 60 percent) of the potential energy in the uranium ores.

The predominant nuclear system utilized in the U. S. currently is the uranium dioxide fueled, light-water moderated and cooled nuclear power plant. This cycle accounts for most of the electric power generated by nuclear fuels in the U. S. today, and is expected to predominate through most of the next decade. In the light-water reactor, the heat energy created in nuclear fission is removed by the circulation of water through the fuel core. The heated water produces steam which turns turbine generators. The water thus functions both as a coolant to transport the heat released in fission and as a moderator to slow down the fast neutrons produced in fission. Fuel is in the form of slightly enriched uranium dioxide pellets encased in tubing of a zirconium alloy. The fuel rods are assembled into bundles. Control rods are strategically placed in the fuel to control the rate of the nuclear reaction.

The light-water reactor supporting fuel cycle includes the following components. Some of these are common to other fuel cycles.

1. Mining uranium ore.
2. Processing the ore to produce uranium concentrates.
3. Production of uranium hexafluoride from uranium concentrates to provide feed for isotopic enrichment.
4. Isotopic enrichment of uranium hexafluoride to attain reactor enrichment requirements using the gaseous diffusion process.
5. Fabrication of nuclear reactor fuel including converting uranium hexafluoride to uranium dioxide, pelletizing, encapsulating in rods and assembling fuel elements.
6. Production of power from the reactor.
7. Reprocessing irradiated fuel to recover plutonium produced and unburned uranium and converting the uranium to uranium hexafluoride for recycle through the gaseous diffusion plant for reenrichment.
8. Radioactive waste management of high level and other wastes, including long-term storage of wastes.
9. Transportation of materials to and from each of the above operations.

RESOURCE BASE

AEC develops estimates of two types of uranium resources. "Reserves" refers to known deposits that can be economically produced at a given market price. "Potential resources" refers to additional uranium that may exist in unexplored extensions of known deposits or in undiscovered deposits within or near known uranium areas. These estimates do not represent the total uranium resources of the U. S.

as other uranium areas undoubtedly exist and will be discovered in the future. However, discovery of new deposits outside known mining areas in the long term may become increasingly difficult and expensive.

Each resource category is also qualified by market price. Estimates at lower prices are more precise because they are based on better data from industry exploration, which has focused on lower price reserves.

Of reserves of U_3O_8 at $8 a pound, about 50% is found in New Mexico, 35% in Wyoming, 5% in Texas, 3% in Colorado, and 3% in Utah. The remainder is scattered throughout the Western United States. As of the beginning of 1973, AEC estimates that $10 reserves of U_3O_8 in conventional deposits in the Western U. S. (including $8 per pound U_3O_8 reserves) were 337,000 tons. Potential resources of U_3O_8 in the Western U. S. were an additional 450,000 tons at $8 and 700,000 tons at $10. In 1972, approximately 42% of U_3O_8 production came from New Mexico, 33% from Wyoming, 7% from Colorado, and 6% from Utah.

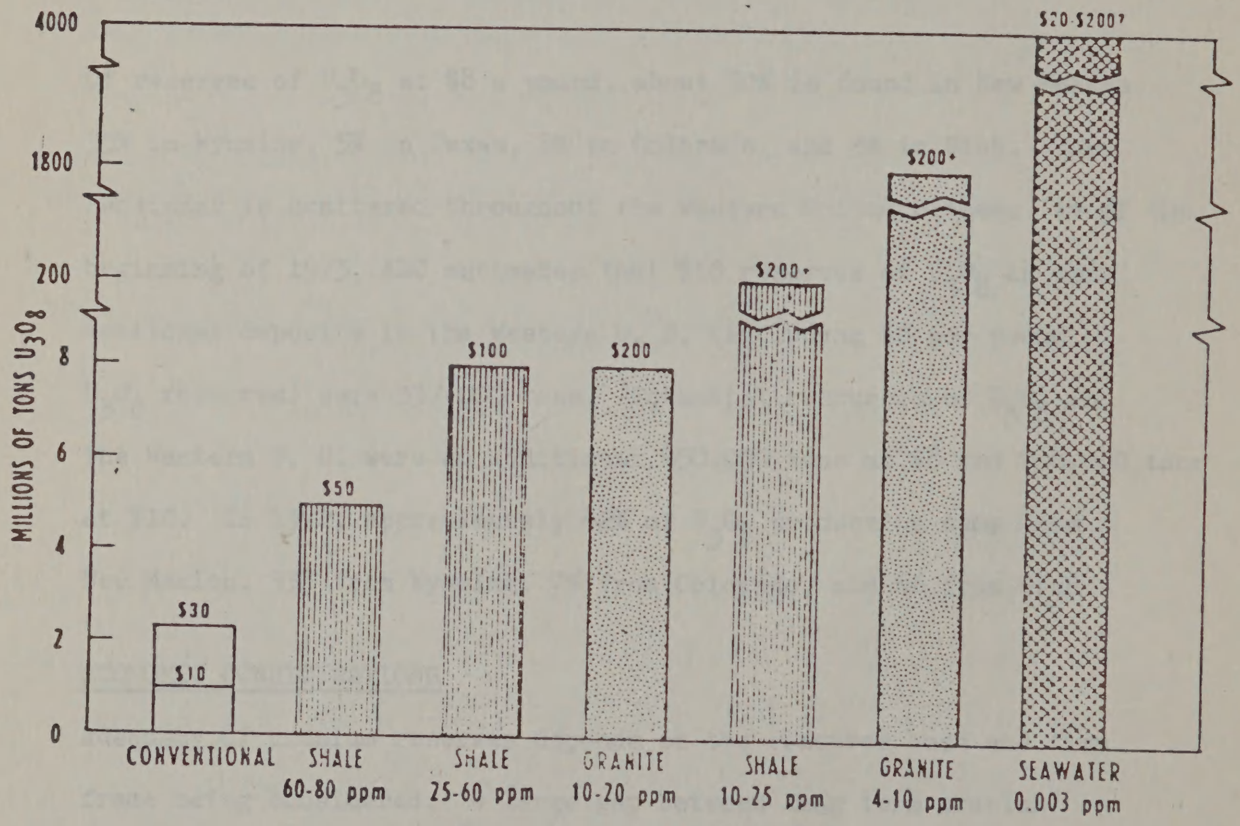
ECONOMIC CONSIDERATIONS

Adequacy of uranium reserves depends on the resource base and time frame being considered. A large gap between long term uranium requirements and resources is shown if resources are confined to the \$8 per pound U_3O_8 reserves. This gap narrows progressively with the inclusion of \$8 per pound potential resources, \$10 per pound reserves, \$10 per pound potential resources, and so on. If shorter term demand is considered, reserves at \$8 per pound are about equal to the next 10 to 11 years requirements.

The first figure below shows U. S. uranium resources at different prices. The second shows uranium production, reserves, and potential. 1/ These figures may be compared to AEC estimated requirements from 1972 through 2000 of 2,400,000 tons of U_3O_8, or about 10 times total past production in the U. S. to date.

Figure VI-1

U.S. URANIUM RESOURCES AT \$10 TO \$200 PER LB. U_3O_8



1/ Remarks by Robert D. Nininger, Asst, Director of Raw Materials, Div. of Production and materials management, AEC, before the Atomic Industrial Forum, Uranium Seminar, Oak Brook, Illinois, March 27, 1973.

Table VI-1

PRODUCTION, RESERVES, AND POTENTIAL COMPARED TO REQUIREMENTS

Tons U_3O_8

	1948-1971 Production	Cut-off Cost	Reserves	Potential	Total	Total Reserves and Potential
Ambrosia Lake, New Mexico (the largest U. S. uranium district)	64,000	$ 8	58,000	29,000	151,000	87,000
		$15	87,000	59,000	210,000	146,000
Other New Mexico	31,000	$ 8	79,000	196,000	306,000	275,000
		$15	113,000	393,000	537,000	506,000
Wyoming	43,000	$ 8	95,000	100,000	238,000	195,000
		$15	164,000	275,000	482,000	439,000
Other U. S.	97,000	$ 8	41,000	135,000	273,000	176,000
		$15	156,000	273,000	526,000	429,000
Total U. S. A.	235,000	$ 8	273,000	460,000	968,000	733,000
		$15	520,000	1,000,000	1,755,000	1,520,000

Although uranium at prices up to $15 per pound may be economically competitive in water reactors in the future, the effort to develop the capability to produce such low-grade ore will not begin until there are indications of a market at that price. The uranium content of $15 resources ranges from 0.10-0.12% U_3O_8 compared to 0.20-0.22 for $8 resources. Therefore, almost twice as much ore must be processed to produce an equivalent amount of uranium. Depending on the characteristics of lower grade deposits, much more than twice as much material may be displaced. Thus, industry materials handling capacity would have to at least double.

Capital costs of nuclear power plants have increased in the past few years. The AEC has developed a method to estimate costs for a specific power plant on the basis of a reference case cost. A detailed cost model is selected and modified using data input for the specific project, such as plant type and location, beginning and start-up dates and rate of interest during construction. The model case may be broken down into over a hundred cost accounts, each of which can be adjusted separately. This procedure was used to develop the following estimates for the base capital cost of a 1000 Mwe pressurized water reactor reaching commercial operation in 1980.

Table VI-2
Capital Estimates for a 1000 Mwe
Pressurized Water Reactor for Operation in 1980
($ million)

1. Land	1
2. Structures and site facilities	38
3. Reactor/boiler plant equipment	59
4. Turbine plant equipment	68
5. Electric plant equipment	16
6. Miscellaneous plant equipment	5
7. TOTAL DIRECT COST	187
8. Contingency allowance	12
9. Spare parts allowance	1
10. Indirect costs	49
11. TOTAL-MID-1972 COST	249
12. Escalation to start of construction*	—
13. TOTAL AT START OF CONSTRUCTION	249
14. Interest during construction	63
15. Escalation during construction*	99
16. TOTAL AT COMMERCIAL OPERATION	411
17. Allowance for cooling towers	20
18. Allowance for near-zero radwaste system	4
19. Allowance for SO₂ removal system	—
20. TOTAL COST AT COMMERCIAL OPERATION IN 1980	435

*Escalation rates are 5%/year for equipment and materials and 10%/year for site labor.

Source: Capital cost calculations for Future Power Plants, compiled from AEC source material and summarized by F.C. Olds, Senior Editor, Power Engineering, January, 1973

Installed nuclear capacity is currently 17,000 MW. The AEC projects 1/ capacity will increase to 52,000-57,000 MW by 1975, 127,000-144,000 MW by 1980, and 256,000-332,000 by 1985. The most likely estimates are 132,000 MW in 1980, 280,000 MW in 1985, and 1,200,000 MW by the year 2000.

ENVIRONMENTAL IMPACT

Impacts on Air Quality

Nuclear power plants, unlike fossil fuel plants, do not emit the usual products of combustion such as particulates, sulphur oxides, and nitrogen oxides. Hence, air pollution problems from such emissions do not occur. However, they do produce radioactive emissions whose release must be strictly limited if adverse affects to the health of humans and other biota are to be avoided.

In the normal operation of nuclear generating units, there are small amounts of radionuclides discharged in the cooling water and gaseous plant effluents. Assuming that present standards will be maintained and enforced (these limit the release of radioactivity to no more than would expose an individual at the plant boundary to 1% of the individual maximums allowed), the effects of the amounts released are likely to be negligible, as the average

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1/ Wash-1139(72) Nuclear Power 1973-2000, USAEC, Dec. 1, 1972.

additional annual dose which the affected population would receive, would be three to four orders of magnitude less than the average level of natural radiation exposure.

Impact on Water Quality

Operation of the light water reactor plants will generate considerable amounts of waste due to their comparatively lower thermal efficiency (around 33% compared to 40% for new coal-fired fossil-fueled thermal plants). Given this difference in efficiency and on the assumption that fossil fuel plants release around 15% 1/ of their waste heat directly into the atmosphere, a light-water reactor would release approximately 50% 2/ more waste heat into its cooling water than a fossil fuel plant of similar size. The effects of this waste heat will depend upon the cooling method used and the location of the plant.

The use of cooling ponds would produce less forced evaporation than wet cooling towers, but haze, fog, cloud, and ice formation would still occur during periods of sub-freezing temperatures.

1/ Energy Research Needs, Oct. 1971, Sec. IX, Resources for the Future, pg. 19.

2/ Ibid, Section VI, pg. 15.

Assuming a 15-20 degrees F temperature rise, a "once through" method of direct discharge into the original source for a 1,000 MW plant would require 270-360 billion gallons of water per year. The effects of using a "once through" method of cooling heated water depend in part on the size of the body of water into which this heated water is discharged. The effects along ocean sites, the Great Lakes, and very large rivers are likely to be modest as the heat is more readily dispersed and more easily avoidable by aquatic species. Along smaller lakes and rivers or in bays with limited circulation, the effects can be more significant. Within the affected areas, higher water temperature may produce fish kills, interfere with fish reproduction, disrupt food chains, decrease dissolved oxygen content, drive out desirable aquatic species and encourage the growth of undesirable algae which may speed-up eutrophication. However, sometimes the heat can be used for aquaculture and other beneficial uses.

Impact on Land Quality

Most uranium mining takes place in relatively isolated semi-desert areas distant from large population centers. The removal of vegetative cover and the creation of overburden and waste rock result from uranium mining. In 1972, 40% of production came from underground mines with most of the remainder coming from open-pit mines. Open-pit mining disturbs a few hundred acres over a reactor lifetime, reducing suitability of the area for other uses such as grazing wildlife and some types of outdoor recreation. In underground mining, the extraction of ores requires some accumulation of waste rock in dump areas but causes much less disturbance than open-pit mining. Careful planning for sequential land use, including reclamation of mined land and the backfilling of mined-out stopes and pits with rock, can substantially reduce land use problems.

Because of low concentration of U_3O_8 in uranium ore, most of the ore milled ends up as low level radioactive tailings that must be retained in well constructed tailings dams to prevent erosion and leaching. Tailings are not a suitable environment for future habitation and are unsuitable for use as fill material in construction where human occupancy is involved. To minimize erosion from above ground storage, the tailings can be covered with gravel or dirt. Above ground storage of tailings requires up to 100 acres of land for a reactor lifetime and displaces other uses.

Under current siting criteria, nuclear plants would be located at some distance from population centers. Assuming 500 acres per site (based upon an exclusion area of one-half mile radius around each plant), and an average of three 1,000 MW units per site, the construction of 3,000 MW of additional nuclear capacity would thus require 500 acres from which other uses would be excluded. Cooling ponds require additional acreage (an estimated 1,000-2,000 acres per 1, 000 MW unit).

Depending on the capacity of the transmission lines needed, the transmission line rights-of-way would require the use of ten to fifteen acres per mile of line. Certain types of development, such as residences, would be excluded although such land would still be largely available for other purposes, such as recreation. Additional transmission lines for electricity are required regardless of how the electricity is produced, whether by nuclear plants, hydropower, or fossil fuels.

Plant construction would present short-run environmental problems such as the erosion of excavated materials and subsequent siltation.

Control of Radioactive Emissions

Risk of Accidents

The operation of nuclear plants poses some risk of accidents. Nuclear plants are designed to minimize accidents or their adverse effects if one does occur, utilizing a "defense-in-depth" principle. This includes siting reactors in remote areas, designing and constructing plants to prevent accidents and to contain the effects of accidents were they to occur. Plants are designed to withstand a design basis accident, defined as the worst malfunction considered to have a probability of occurrence high enough to warrant corrective action. For light-water reactors, the worst design basis accident considered is usually a major rupture in the primary cooling system.

The maximum radiation dose which could be received at the site boundary if such an accident were to occur is estimated for most plants not to exceed the annual dose obtained from natural radioactivity.

Transportation

The nuclear fuel cycle requires the transportation of radioactive materials by truck or rail at several stages. The transportation of spent fuel elements from reactors to processing plants and high-level waste from reprocessing plants to storage sites poses a potential hazard of considerable magnitude. Transportation regulations and cask designs have been developed to insure that even if accidents in transporting these materials do occur, no radioactivity will be released to the environment.

Fuel Reprocessing

Spent fuel assembles from reactors are first partially cooled at the plant site and then transported to fuel reprocessing plants where useable nuclear fuel materials are recovered from them and radioactive wastes are separated. At present there are two such fuel reprocessing plants and one more is under construction. Each reprocessing plant can serve 30 to 50 nuclear plants. While radioactive emissions during fuel reprocessing are greater than those occurring during normal power generation, the estimated dose to the affected population is still two orders of magnitude below natural levels. Hence, the impact of these emissions is not expected to be significant, even though the chronic effects of such low level radioactivity are not yet wholly known.

Radioactive Waste Storage

High-level radioactive wastes remaining after reprocessing are first concentrated and stored in solution for five years, then solidified, sealed in containers, and put into long-term storage. An incremental capacity of 1,000 MW would produce around 8,000 to 10,500 gallons of high-level waste per year, using a cumulative storage capacity of 40,000 to 54,000 gallons. This liquid waste, when evaporated, would yield around 80 to 105 feet/year in solid waste materials for each year of operation.

Because of their high concentrations of radioactive nuclides and very slow rates of decay, these waste materials must be isolated from the biosphere for hundreds of thousands of years if adverse effects to living organisms are to be totally avoided. Waste is presently being stored in below the surface man-made engineered storage facilities. Research is being conducted to find a permanent storage repository. As part of this research, pilot studies of storage in salt beds are being conducted.

SPECIAL CONSIDERATIONS

Florida phosphate rock contains low concentrations of uranium. The uranium is dissolved during wet-process phosphoric acid production, and may be recovered as a byproduct. During World War II a byproduct uranium plant operated in Florida. Production costs ranged from \$10 to \$30 per pound of recovered U_3O_8. After the discovery of high grade domestic uranium deposits, the byproduct plant was shut down. No uranium is currently being recovered from Florida phosphate rock.

The Bureau of Mines has estimated that Florida phosphate rock reserves of 2.0 billion short tons contain 300,000 short tons of U_3O_8. This estimate is based on an average U_3O_8 content of 0.015%. However, the Bureau estimates that only 12.5%, or 37,500 tons of U_3O_8 should be considered as available for byproduct recovery at a price of \$10 per pound. Assuming a 95% recovery rate in acid production, and a 90% recovery rate in uranium production, an overall recovery factor of 85.5% may be assumed for U_3O_8 byproduct production. Thus, slightly more than 32,000 short tons of U_3O_8 could be recovered during wet-process phosphoric acid production, if the price of uranium rose from current price levels of \$6-7 per pound to at least \$10 per pound. The uranium content of phosphate rock used in electric furnace phosphorus production, normal superphosphate production, direct application, and exports cannot be recovered.

Although Florida phosphate rock does contain a potentially significant amount of uranium, it does not present a readily available energy source. Uranium production from phosphate rock is directly dependent on the production of wet-process phosphoric acid. The cost of producing only uranium from Florida phosphate rock is estimated to range from \$60 to \$100 per pound. Such operation would product monumental environmental problems. Without considering overburden, and assuming 100% recovery, approximately 3.3 short tons of phosphate rock would have to be mined for each pound of U_3O_8 recovered. Current phosphate rock mining operations have been cited as a source of environmental degradation, and considerable effort is being expended to reduce such problems. It is unlikely that any solution could be found to the large scale disturbance which would occur if only uranium were mined in Florida.

U. S. uranium reserves were estimated by the U. S. Bureau of Mines to be 330,000 short tons of U_3O_8, as of January 1, 1972, at a price of \$10 per pound. The Florida uranium would account for less than 10% of this estimate, and would become available only at the production rate of wet-process phosphoric acid.

Although Florida phosphate rock does contain a potentially significant amount of uranium, it does not present a readily available energy source. Uranium production from phosphate rock is directly dependent on the production of wet-process phosphoric acid. The cost of producing only uranium from Florida phosphate rock is estimated to range from $60 to $100 per pound. Such operations would produce monumental environmental problems. Without considering overburden, and assuming 100% recovery, approximately 3.3 short tons of phosphate rock would have to be mined for each pound of U_3O_8 recovered. Current phosphate rock mining operations have been cited as a source of environmental degradation, and considerable effort is being expended to reduce such problems. It is unlikely that any solution could be found to the large scale disturbance which would occur if only uranium were mined in Florida.

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RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

Nuclear capacity required to generate electricity that would replace the expected MAFLA production depends on whether the oil and gas were employed in end uses or in electricity generation. Substitution for end uses of all the oil and gas would require 20 to 33 plants of 1,000 megawatt capacity. At an average of three 1,000 MW units per site and 500 acres per site, these plants would occupy 3,500 to 5,500 acres. Cooling ponds, which require an estimated 1,000 to 2,000 acres per 1,000 megawatt unit, would occupy 20,000 to 66,000 acres. High-level radioactive wastes would amount to 160,000 to 330,000 gallons per year, yielding about 3,400 to 7,000 cubic feet per year in solid wastes. To supply fuel for these plants would require 11,200 to 18,500 tons of U_3O_8 for the first core fuels and 3,500 to 5,700 tons of U_3O_8 for annual reloads without plutonium recycling and 2,400 to 4,000 tons with plutonium recycling. At an average ore grade of 0.20 percent, a total ore output of 5.6 to 9.3 million tons of ore would be needed to supply the uranium for the first core fuels and an annual output of from 1.2 to 2.0 million tons for reloads (with plutonium recycling).

Nuclear capacity required to substitute for the electricity that could be generated by the MAFLA oil and gas would be 11 to 18 plants of 1,000 megawatt capacity. These plants would occupy 2,000 to

3,000 acres and their cooling ponds would occupy an additional 11,000 to 36,000 acres. High-level radioactive wastes would amount to 88,000 to 190,000 gallons per year, yielding about 880 to 1,890 cubic feet per year in solid wastes. To supply the fuel would require 6,100 to 10,100 tons of U_3O_8 for the first core fuels and 1,900 to 3,100 tons of U_3O_8 for annual reloads without plutonium recycling and 1,300 to 2,200 tons with plutonium recycling. At an average ore grade of 0.20 percent U_3O_8, a total ore output of about 3.1 to 5.1 million tons of ore would be required to supply uranium for the first core fuels and an annual output of 0.7 to 1.1 million tons more for reloads (with plutonium recycling).

The smallest nuclear capacity required to substitute for the MAFLA sale would be 11,000 megawatts, in the case where reserves found and produced were not much more than the lower estimate (270,000 barrels of oil and 0.34 trillion cubic feet gas produced daily) and where the gas were used to generate electricity. The feasibility of nuclear power as an alternative depends on its rate of development. If reserves found in the MAFLA tracts were near the high estimate and the oil and gas were diverted to end uses at maximum efficiency, nuclear power could probably not replace the expected MAFLA production in the time frame anticipated.

7. Energy Imports

a. Oil Imports

PROJECTIONS OF FUTURE IMPORT LEVELS

Based upon the analysis presented in section I, oil imports will play an important role in fulfilling the United States demand for petroleum. Using figures presented in that section, the following table shows the expected demand for petroleum, the expected domestic production and supplemental supplies that will be required to fulfill demand. Through 1980, if domestic production is not stimulated, these supplemental supplies will come in the form of increased imports. After that time incremental production may be possible from some synthetic sources (oil shale, tar sands, etc.), but imports will still provide the predominant portion.

Table VII-1

Total U.S. Petroleum Demand Domestic Production and Supplemental Supplies Through 2000
(million barrels/day)

	1971	1975	1980	1985	2000
Total Petroleum Demand	15.1	17.4	20.9	25.0	35.6
Total Domestic Production	11.3	11.0	11.8	11.6	10.6
Supplemental Supplies	3.8	6.4	9.1	13.4	25.0

Source: "U. S. Energy Through the Year 2000", U. S. Department of the Interior, December, 1972, p. 43.

The National Petroleum Council's analysis of the energy situation provides some other projections of imports through 1985. 1/ For their analysis, the NPC developed four different cases based upon varying economic conditions and oil and gas finding rates. Case I represents the best of all conditions, while Case IV represents the worst and Cases II and III are intermediary conditions. The following table presents NPC's projections of imports that will be needed to balance demand.

Table VII-2
Projected Level of Oil Imports (NPC)
(millions of barrels/day)

Case	1975	1980	1985
I	7.2	5.8	3.6
II	7.4	7.5	8.7
III	8.5	10.6	13.5
IV	9.7	16.4	19.2

1/ National Petroleum Council, U. S. Energy Outlook, December, 1972.

Another way of viewing oil imports is to examine their relationship to total petroleum supply. Figure VII-1 shows the percentage of the total U. S. petroleum supply made up by imports. The solid line from 1971 represent projections made by the Interior Department while the broken lines represent projections by NPC. This graph demonstrates the increasing importance of imports which is caused by rising demand and and stationary domestic production.

PRESENT OIL IMPORT POLICIES

Until President Nixon's energy message of April 18, 1973, imports of crude oil, unfinished oil, and oil products were limited under the Mandatory Oil Import Program established in 1959 by Presidential Proclamation 3279. In his message, the President stated, that "the Mandatory Oil Import Program was established at a time when we could produce more oil at home than we were using. . . Today, however, we are not producing as much oil as we are using, and we must import ever larger amounts to meet our needs. As a result, the current Mandatory Oil Import Program is of virtually no benefit any longer." For this reason the President adopted a program whereby controls and tariffs upon imports of crude oil, unfinished oils, and finished petroleum products were lifted; such imports were made subject to a gradually increasing scale of license fees; and the levels of fee-exempt imports were gradually reduced. However,

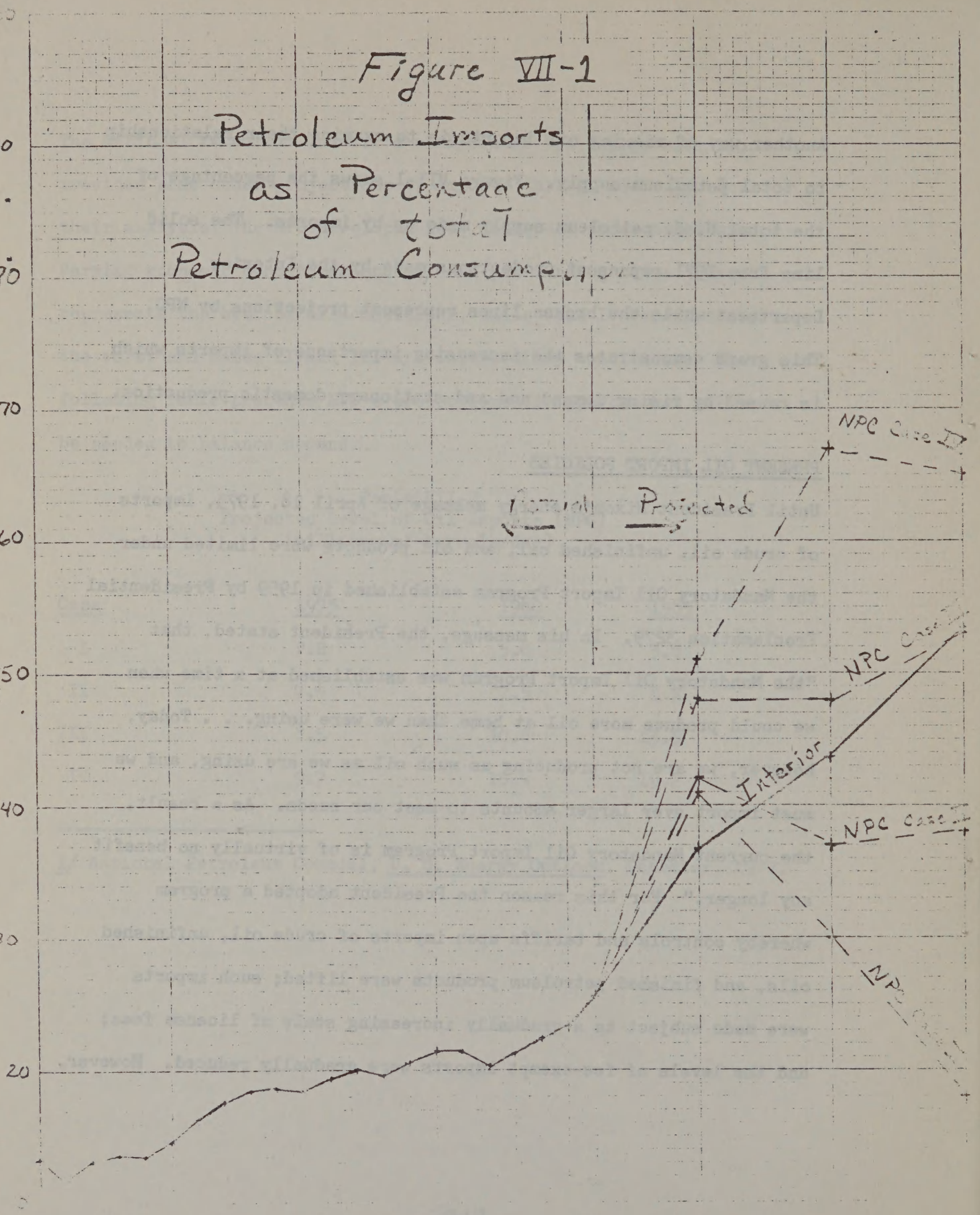


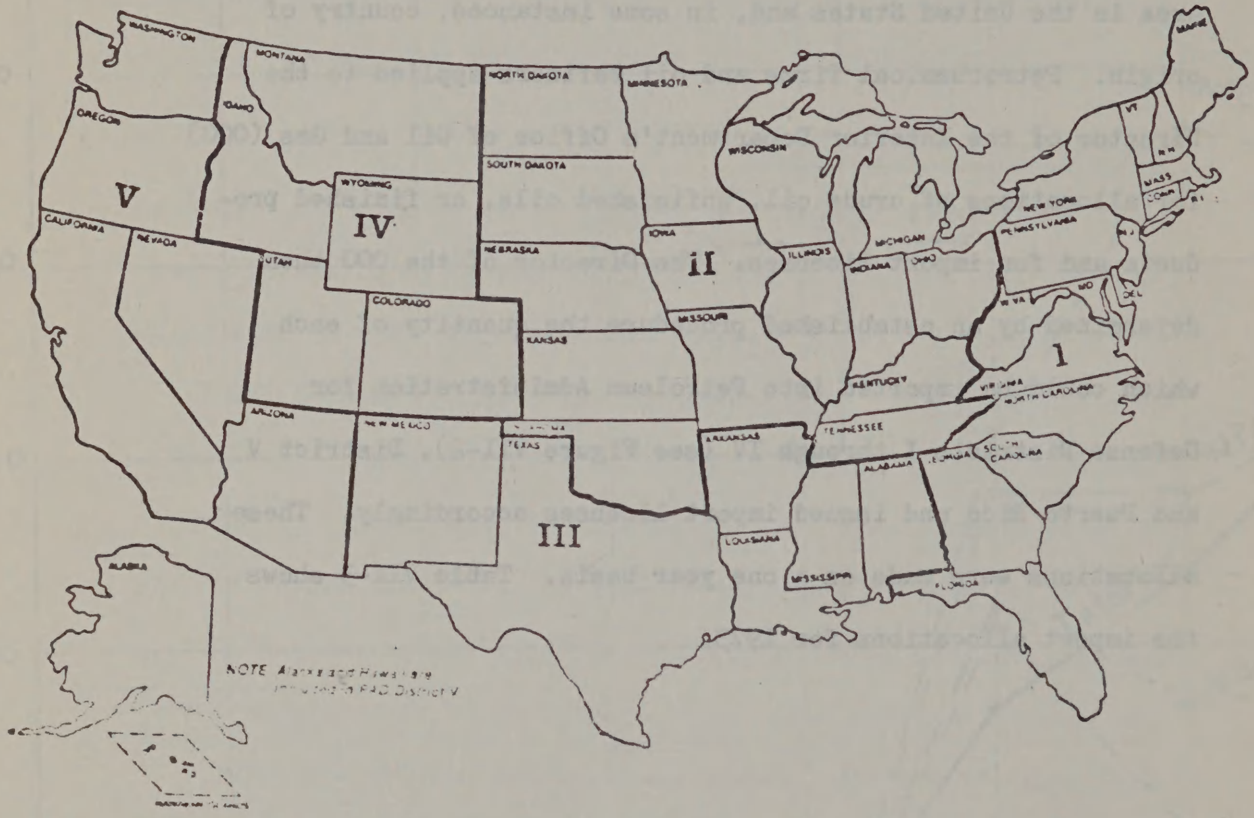
Figure VII-1
Petroleum Imports as Percentage of total Petroleum Consumption

fee-exempt imports, designed to encourage the construction of expanded domestic refinery and petrochemical capacity and to encourage exports of petrochemicals, will continue to be available.

Under the quota system, the level of petroleum imports were restricted on the basis of product (commodity), geographical area in the United States and, in some instances, country of origin. Petrochemical firms and oil refiners applied to the Director of the Interior Department's Office of Oil and Gas (OOG) for allocations of crude oil, unfinished oils, or finished products and for import licenses. The Director of the OOG then determined by an established procedure the quantity of each which could be imported into Petroleum Administration for Defense Districts I through IV (see Figure VII-2), District V and Puerto Rico and issued import licenses accordingly. These allocations were made on a one year basis. Table VII-3 shows the import allocations for 1973.

Figure VII-2

Petroleum Administration for Defense (PAD) Districts



NOTE: Alaska and Hawaii are included in PAD District V

Table VII-3
Import Allocations (thousands barrels/day)
PAD Districts I-IV

	1973
Crude and Unfinished Oils	2,886.0
Finished Products (excluding residual fuel oil)	133.0
Residual Fuel Oil	2,900.0
District V	
Crude and Unfinished Oil	942.5
Finished Products (excluding residual fuel oil)	7.5
Residual Fuel Oil	75.6

Through April 30, 1974, under the new program importers will not be required to pay a fee on their previously allocated import levels. The amount of duty-free imports which will be permitted will be reduced each year until reaching zero in 1980. In 1974, 90 percent of the initial allocation will be exempt from the license fee; in 1975, 85 percent; in 1976, 65 percent; in 1977, 50 percent; in 1978, 35 percent; in 1979, 20 percent; and in 1980, zero. [1]

The license fees will also change over time. The following table shows the schedule for fee increases for crude oil, for residual fuel oil, unfinished oils and refined products other than gasoline, and for gasoline.

1/ "New Import Program Sets Up 'Fees'", The Oil Daily, April 19, 1973, p. 1.

Table VII-4
Projected Fee Schedule 1/
(¢/barrel)

Date	Crude Oil	Residual fuel oil and refined products other than gasoline	Gasoline
May 1, 1973	10.5¢	15.0¢	52.0¢
Nov. 1, 1973	13.0	20.0	54.5
May 1, 1974	15.5	30.0	57.0
Nov. 1, 1974	18.0	42.0	59.5
May 1, 1974	21.0	52.0	63.0
Nov. 1, 1975	21.0	63.0	63.0

The Office of Oil and Gas will continue to administer the oil import program. A license to import will be granted upon application to that office. The Oil Policy Committee, under the Deputy Secretary of the Treasury, will be responsible for policy decisions related to oil imports. The license fees will be reassessed from time to time to be sure that the goals of stimulating domestic production and increasing refinery capacity are being met.

1/ "New Import Program Sets Up 'Fees'", The Oil Daily, April 19, 1973, p. 4.

IMPORT FLOW PATTERN

Sources of Imports

In the past, the United States has received most of its imports from Western Hemisphere sources. Because of declining resource availability and increasing domestic demand, it does not seem likely that these countries will be able to meet the future U. S. need for imports. Table VII-5 shows estimates made by the NPC of Western Hemisphere liquid hydrocarbon supply-consumption balances. The estimates are based on their Case III supply estimates. In 1960 the Western Hemisphere was able to essentially maintain a balance in the supply and consumption of petroleum. This balance was almost achieved again in 1965.

The availability of Latin American oil was a major factor in reaching these balances. In the future, however, the increases in Latin American consumption are expected to be greater than increases in production. This factor combined with the great increases in United States consumption will cause larger and larger deficits in the Western Hemisphere petroleum supply-demand balance.

Table VII-5

WESTERN HEMISPHERE LIQUID HYDROCARBON SUPPLY – OIL CONSUMPTION BALANCE (1960-1985)*

(MMB/D)

	1960	1965	1970	1975	1980	1985	
						Low	High
Local Oil Consumption (Excluding Exports)							
United States	9.8	11.5	14.7	18.3	22.3	25.8	
Canada	0.9	1.1	1.5	1.9	2.3	2.7	3.0
Latin America	1.7	2.1	2.8	3.9	5.1	6.5	7.0
Total Western Hemisphere	12.4	14.7	19.0	24.1	29.7	35.0	35.8
Conventional Liquid Hydrocarbon Production							
United States	8.0	9.0	11.3	9.8	11.6	11.8	
Canada	0.5	0.9	1.5	2.2	3.0	3.7	
Latin America	3.8	4.7	5.3	5.8	6.7	7.0	
Total Western Hemisphere	12.3	14.6	18.1	17.8	21.3	22.5	
Synthetic Liquid Production							
United States	–	–	–	–	0.1	0.5	
Canada	–	–	–	–	0.4	1.0	
Latin America	–	–	–	–	0.3	0.8	
Total Western Hemisphere	–	–	–	–	0.8	2.3	
Total Liquid Hydrocarbon Production (Conventional Plus Synthetic) Available for Net Export or (Imports Required)							
United States	(1.8)	(2.5)	(3.4)	(8.5)	(10.6)	(13.5)	(13.5)
Canada	(0.3)	(0.2)	–	0.4	1.1	2.0	1.7
Latin America	2.1	2.6	2.5	1.9	1.9	1.3	0.8
Total Western Hemisphere	–	(0.1)	(0.9)	(6.2)	(7.6)	(10.2)	(11.0)

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* All estimates are on a Case III supply basis.

Source: N.P.C. U. S. Energy Outlook. p. 262.

Future increases in oil imports will come primarily from the Middle East and North Africa. It has been estimated that almost 80 percent of the non-communist world oil reserves lie in these two areas. 1/

Problems with the security of supply, balance of payments, and United States off loading terminal capacity could arise due to an increase in imports from this region. Some of these problems will be examined later in this section. Using the Department of Interior projections of import levels the following table shows the breakdown of oil imports by source.

Table VII-6
Imports by Source
(million barrels/day)

	1975	1980	1985 2/ Low	1985 2/ High
Western Hemisphere	2.3	3.0	3.3	2.5
Eastern Hemisphere	4.1	6.1	10.1	10.9
Total Imports	6.4	9.1	13.4	13.4

1/ U. S. Department of Commerce, Maritime Administration, Offshore Terminal System Concepts, Vol. I, Figure No. 1-13.

2/ Low and High values refer to the expected Western Hemisphere oil consumption in the previous table.

Destination of Imports

The bulk of oil imports in the past have entered PAD District I. This district has a high demand for oil caused by a concentration of population and industry and very limited oil production. Figures in Table VII-7, which presents 1970-PAD District supply-demand balances, show that 71.5 percent of 1970 imports entered this district. Table VII-8 which shows 1985 PAD District supply and demand balances based on NPC's Case III, indicates that PAD District I will continue to have large deficits. In 1985, District I will require shipments of about 10 million barrels/day. Even if all surplus domestic production were shipped to District I, which seems unlikely given the projected deficit in District II, there would still need to be about 7.4 million barrels/day of foreign oil brought into the East Coast.

Table VII-7 - 1972 Supply Distribution and Sources
(Thousand barrels per day)

PAD Districts	Production Crude oil & NGL	Domestic Receipts: Crude and NGL		Domestic Receipts: Refined Products		Imports: Crude and NGL		Imports: Refined Products	
District I	88		284		2,996		971		2,162
		(II)	24	(II)	61	Canada	113	Canada	91
		(III)	257	(III)	2,932	Other West. Hem.	243	Other West. Hem.	1,863
		(IV)	3	(IV)	--	Africa	402	Europe	170
		(V)	--	(V)	3	Middle East	213	Africa	28
								Middle East	8
								Other E. Hem.	2
District II	1,279		1,812		759		513		64
		(I)	--		141	Canada	492	Canada	46
		(III)	1,552		594	Other West. Hem.	2	Other West. Hem.	13
		(IV)	260		24	Africa	13	Europe	5
						Middle East	6		
District III	7,943		21		73		77		49
		(I)	9		73	Other West. Hem.	21	Other West. Hem.	43
		(II)	5		--	Europe	1	Europe	4
		(IV)	7			Africa	53	Africa	1
		(V)	--			Middle East	2	Middle East	1
District IV	677		--		53		70		15
				(III)	27	Canada	70	Canada	15
				(V)	26				
District V	1,193		37		145		671		149
		(III)	2	(III)	64	Canada	266	Canada	17
		(IV)	35	(IV)	81	Other West. Hem.	33	Other West. Hem.	70
						Africa	1	Middle East	38
						Middle East	205	Other E. Hem.	24
						Other E. Hem.	166		

Source: Bureau of Mines
Mineral Supply
March 26, 1973

Table VII-8
1985 U.S. Petroleum Liquids
Production 1/ and Demand - NPC Case III
(Thousands of barrels/day)

PAD District	Production	Demand	Surplus (Deficit)
I	201	10,211	(10,010)
II	906	6,859	(5,899)
III	6,458	4,332	2,126
IV	952	697	255
V	3,742 2/	3,688	54
Total United States	12,313	25,787	(13,474)

Source: NPC, p. 276.

In 1970, PAD District II had a large oil deficit which was filled primarily by shipments from District III and imports from Canada. In 1985, if all projected oil surpluses from other districts and all projected Canadian imports (Table 5) were sent to District II, about 1.5 million barrels/day would still be required to achieve a balance in that area.

1/ Includes synthetics.

2/ Includes Alaska.

Increasing oceanborne imports into District II would require an expansion of logistical systems in the upper Midwest and Mid-continent areas. There would have to be construction of new petroleum pipelines and/or additional barge traffic on the Mississippi River system. Significant volumes of imports will undoubtedly enter the Gulf Coast region because a transportation network currently exists which carries oil from the Gulf to the Midwest. It is unlikely, however, that this system could handle the projected increases.

The 1985 surpluses for PAD District V are based on the availability of Alaskan North Slope oil. If the Trans-Alaskan pipeline is built, the West Coast should not need significant quanties of petroleum imports. After that time, however, increased demand will probably have to be met with imports. 1/

TANKER AND TERMINAL REQUIREMENTS

In 1971, total tanker arrivals for the lower 48 States were 67,770. Of these arrivals 56,700(84%) were in PAD District I; 6,650 were in PAD District III(10%); and 4,420 were in PAD District V(6%). Many of the shipments were of products from the Gulf Coast and the

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1/ NPC, op.cit., p. 275.

Carribbean to PAD District I. The average size of tankers carrying imported crude was 29,000 DWT. 1/ To deliver 1971 imports of 3.0 million barrels/day would have required the unloading of the equivalent of 15, 29,000 DWT tankers each day. In 1985, when waterborne imports are projected to rise to 10.7 million barrels/day 2/, 53 tankers of that size would have to be unloaded each day. This increase in throughput and ship traffic can only be met through some type of expansion of United States port capacity.

One of the key factors that will determine the changes that will be required in U. S. port facilities is the size of tankers delivering the oil. Since 1965, tanker construction has been directed almost exclusively toward vessels larger than 65,000 DWT. The development of a successful single point mooring system which allows the unloading of deep draught tankers, and the closing of the Suez Canal in mid-1967, gave impetus to the construction of Very Large Crude Carriers (VLCC's) ranging from 250,000 DWT to 425,000 DWT (presently under construction). A tanker of more than 700,000 DWT

1/ Fact Sheet Attachment to President Nixon's Energy Message, April 18, 1973. (DWT=dead weight ton, the cargo carrying capacity in long tons, 2204 lbs).

2/ NPC., op.cit., p. 181.

has been ordered and a 1,000,000 DWT vessel is in the preliminary planning stage. Figure VII-8 shows the growth of the world tanker fleet by size of vessel from 1960-1971.

The major attraction of large tankers is the reduction in unit transportation costs that they provide. Table VII-9 shows the cost in dollars per ton for the major routes bringing oil to the United States. The Venezuelan route averages about 4,000 nautical miles to the East Coast, the North African route about 8,000 nautical miles and the Persian Gulf route about 24,000 miles. The savings that are possible using larger ships over longer distances are apparent. While a 250,000 DWT tanker would save \$0.50/ton over a 65,000 DWT tanker on the Venezuelan route, it would save \$2.50/ton on the Persian Gulf route. With the shift of primary source of imports from Latin America to the Middle East, this savings will be important for the United States. 1/

1/ In 1971, waterborne oil imports were 149 million tons; in 1980 they are projected to be 533 million tons.

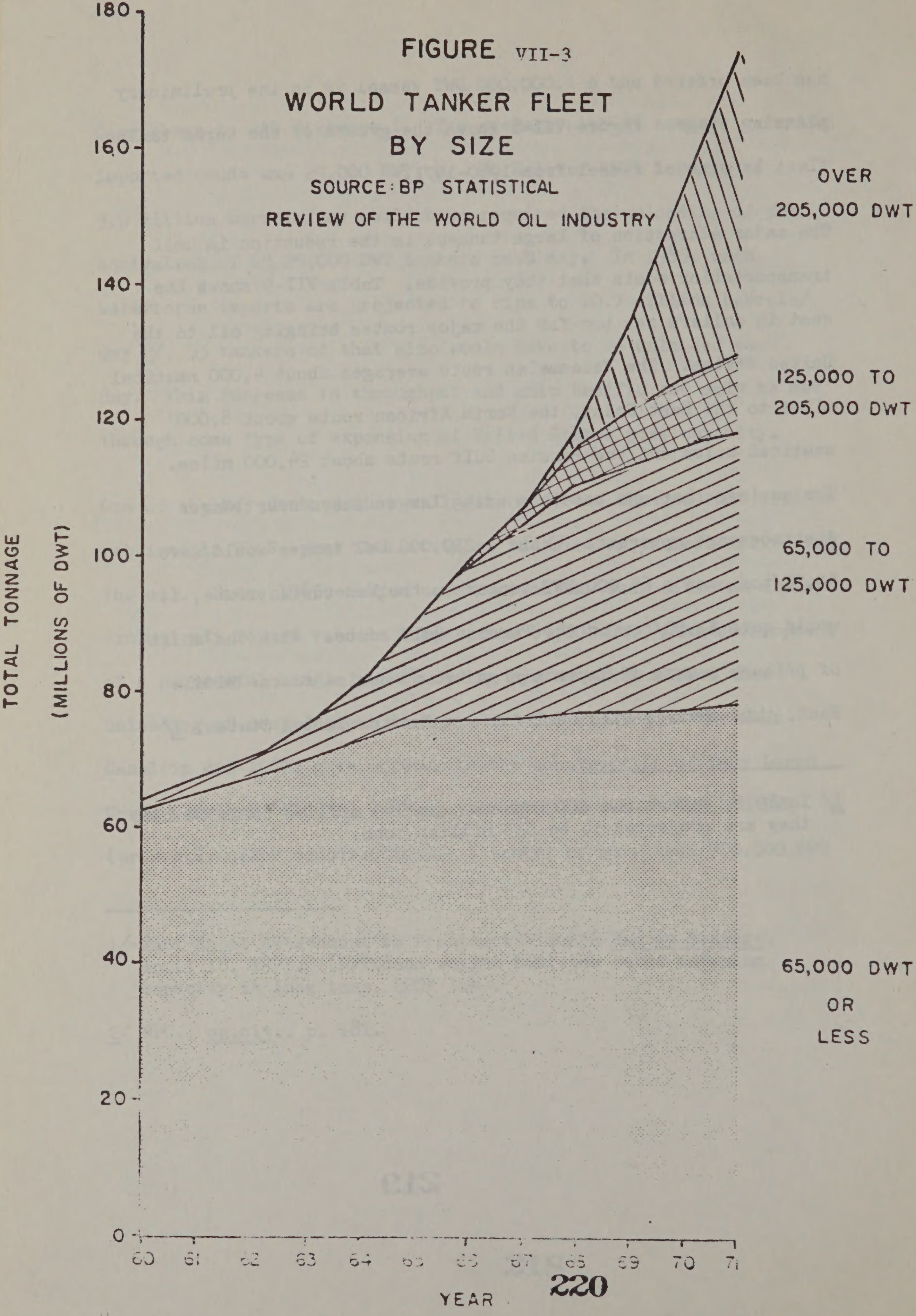

FIGURE VII-3

WORLD TANKER FLEET BY SIZE

SOURCE: BP STATISTICAL REVIEW OF THE WORLD OIL INDUSTRY

Table VII-9
Freight Cost of Transporting Oil
($/ton)

Ship size in DWT	Round-trip Distances in Nautical Miles 4000 1/	8000 2/	24,000 3/
65,000	$1.90	$3.50	$9.05
250,000	1.40	2.50	6.55
326,000	1.25	2.30	6.15
500,000	1.00	1.90	5.45

Source: U. S. Department of Commerce, op.cit. Vol I, Figure 1-32.

The possible reduction in ship traffic is also obvious if larger tankers are used. By using tankers of 100,000 DWT instead of 29,000 DWT, the number of vessels that would have to unloaded each day could be reduced from the equivalent of 53 to the equivalent of 15. By using a 200,000 DWT average, the number of unloadings required each day could be reduced to the equivalent of 7.5.

1/ Venezuelan Route.

2/ North African Route.

3/ Persian Gulf Route.

Because of the savings in transportation costs, the reduction in ship traffic and the lack of new small tankers, it seems inevitable that the United States will be forced to use tankers larger than 100,000 DWT. The problem is that, as shown in Table VII-10 the U. S. does not have any ports capable of handling tankers larger than 100,000 DWT. The East Coast, which requires the greatest amount of imported petroleum, has only one port capable of handling a tanker larger than 55,000 DWT. The study done for the Department of Commerce's Maritime Commission shows that it is neither environmentally nor economically feasible and in some cases physically not possible to dredge existing ports to the depth necessary to allow large tankers to enter.

Several potential alternatives for importing the increased quantities of petroleum were examined in the Maritime Commission's Study. Some of these are: 1) lighten the loads of the VLCC's, offshore of existing ports; thereby reducing the drafts of the vessels sufficiently to allow them to enter the ports and complete the unloading. (This procedure is presently being used to a limited extent in Delaware Bay and New York Bay); 2) develop a fleet of shallow-draft large tankers which could use the present, or moderately deepened, port channels; 3) make use of convential designs such as building a deep-draft terminal in Maine or in Lower

Table VII-10

U.S. TANKER PORTS*

Port	Maximum Vessel Size (DWT)	Port	Maximum Vessel Size (DWT)
Alaska–Nisiki	60,000	Massachusetts–Boston	50,000
California–Long Beach	100,000	New Jersey–Newark	25,000
California–Los Angeles	100,000	New York	55,000
California–Port San Louis Obispo	20,000	Pennsylvania–Philadelphia	55,000
California–San Diego	35,000	Texas–Baytown	30,000
California–San Francisco	35,000	Texas–Beaumont	80,000
Florida–Jacksonville	30,000	Texas–Brownsville	35,000
Florida–Miami	20,000	Texas–Corpus Christi	50,000
Florida–Port Everglades	35,000	Texas–Freeport	30,000
Hawaii–Honolulu	35,000	Texas–Houston	55,000
Louisiana–Baton Rouge	45,000	Texas–Port Arthur	55,000
Louisiana–New Orleans	45,000	Texas–Texas City	45,000
Maine–Portland	80,000	Virginia–Hampton Roads	50,000
Maryland–Baltimore	55,000	Washington–Seattle	45,000

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* George Weber, ed., *International Petroleum Encyclopedia* (1972), p. 407.

Source: NPC, op.cit., p. 282

Delaware Bay, or using single point mooring systems offshore; 4) transfer the oil to the U. S. in small tankers from deep-water terminals being built in Canada and the Bahamas; and 5) make use of offshore deepwater ports, serving an entire region by a transfer system of pipelines and/or feeder vessels. 1/

1/ U. S. Department of Commerce, op.cit., Excutive Summary, p. 16.

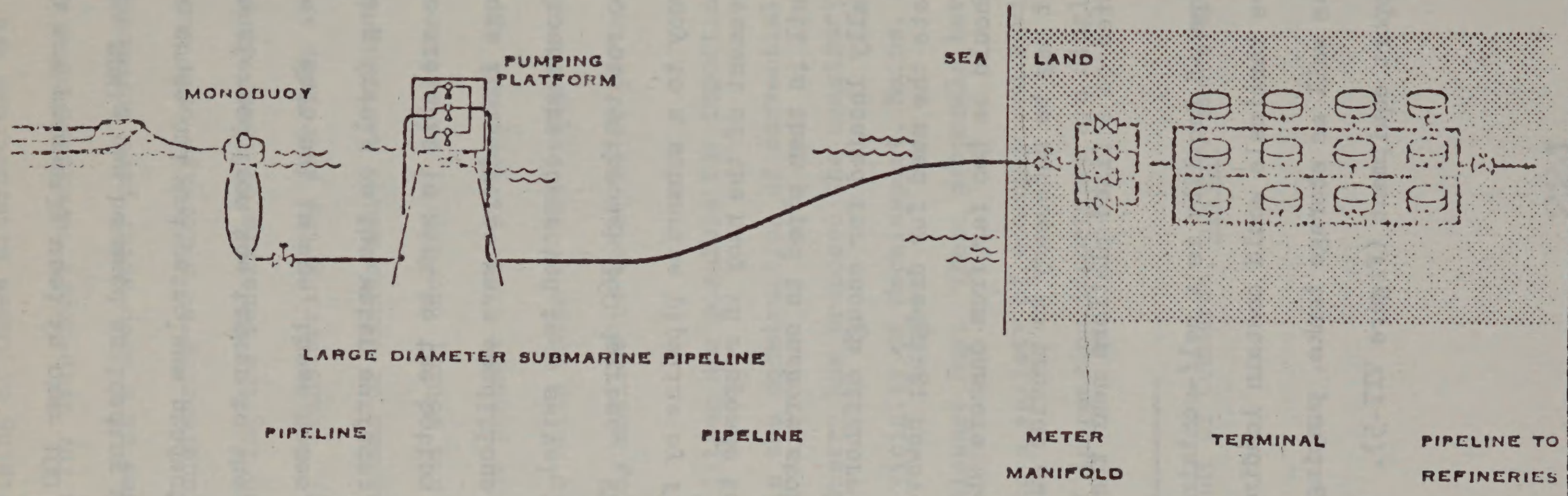
The two most promising of these alternatives are the use of convential design for deep-draft terminals or single point mooring systems and the use of a deep-water port terminal. Offshore lightering and transferring at a foreign port would add an extra cost, thereby reducing the benefits of lower shipping cost offered by larger tankers. Transferring the petroleum from large to small vessels in the Bahamas or Canada would continue the use of a number of small tankers and would, therefore, do little to relieve port congestion. At the present time, it does not appear to be economically practical to build ships of the required capacity with drafts sufficiently shallow to enter U. S. ports. 1/

Two types of facilities are possible for importing large amounts of oil. The first is the construction of convential type facilities. The petroleum industry has proposed the construction of deep-water terminals in the vicinity of Machiasport, Maine, and at Big Stone Beach in Lower Delaware Bay. These proposals have not yet been implemented due to a variety of economic and environmental problems. Another method of increasing importance are Single Point Mooring (SPM)

1/ U. S. Department of Commerce, op.cit. Executive Summary, p. 16.

systems; which are presently used in over 100 locations around the world. The SPM's can be used as loading and unloading facilities for crude oil and petroleum products (Figure VII-4). The oil is transferred from the tanker to the buoy through floating hoses. When not in use, these hoses are normally allowed to swing freely on the water surface; however, newly designed hoses are able to sink to the bottom when out of use to reduce damage from adverse wave conditions and ship maneuvering. The hoses are connected to a swivel on the buoy which allows them to rotate through 360 degrees. The oil is transferred through the buoy to a submarine pipeline by flexible hoses which allow free movement of the buoy in response to wave and tidal action. The oil is then piped to onshore storage facilities. SPM's are usually located far enough offshore and in deep enough water to obviate the need for dredging; however, if the location of the buoy should be too far from onshore storage/utilization facilities, it may be necessary to provide auxiliary pumping capacity mounted on a fixed platform near the buoy.

The second type of facility is a self-contained deep-water port. These offshore terminals would contain loading and unloading facilities, as well as storage tanks, pumping equipment and other necessary support equipment (Figure VII-5). These ports may be



FLOW CHART OF A SINGLE POINT MOORING SYSTEM
(from: "Seadock, A Proposal for a Texas Offshore
Oil Unloading Facility)

Figure VII-4

either platform type structures supported by pilings or artificial islands. These can handle petroleum products as well as dry bulk commodities; however, the size and complexity means greater costs than an SPM. The terminals usually consists of an unloading/loading platform which is connected to the main platform or island. Designs to date normally show a breakwater to provide protection for the terminal. Transshipment from a deep-water complex to mainland storage, processing, or distribution facilities can be made by smaller shuttle vessels, tugbarge systems, pipelines, or trestle-conveyor systems or some combination of these.

Table VII-11 shows the number of VLCC arrivals and the number of berths required for the projected level of imports. In the table one berth represents unloading facilities for one tanker. While one SPM buoy represents one berth. One deep-water port, could contain several berths. The average VLCC size is based on the assumption that the trend toward larger tankers will continue.

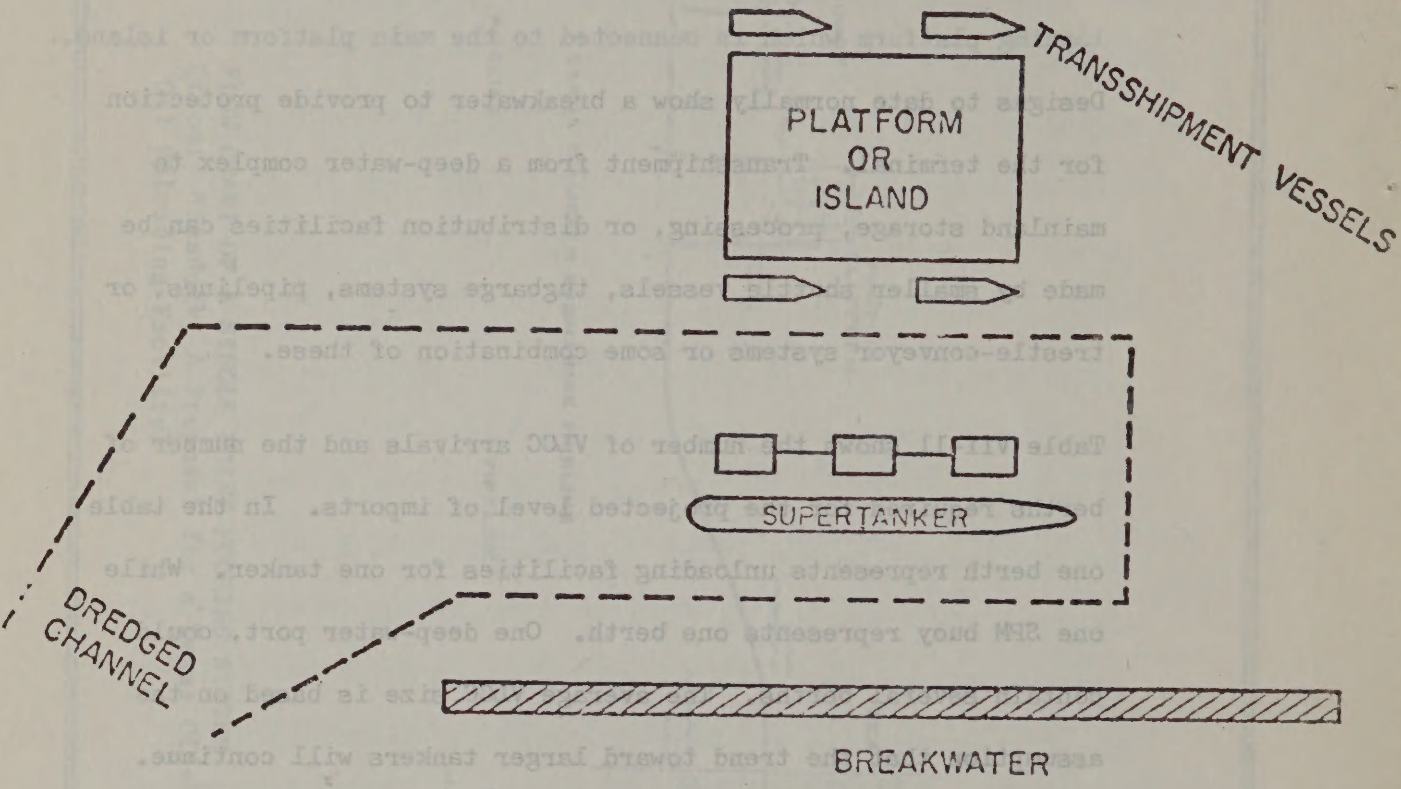


Figure VII-5

ARTIFICIAL ISLAND TYPE DEEPWATER PORT FACILITY
(from: Texas Supertanker Port Texas A&M Univ., Dec. 72)

Table VII-11
Average VLCC Size, Arrivals and Berth Requirements

Year	Average VLCC size (DWT)	Arrivals/Day	Deep-Water Berths Required
1980	200,000	5.0	13
1985	250,000	5.6	15
2000	325,000	7.6	20

REFINERY REQUIREMENTS

As of January 1, 1971, U. S. domestic refinery capacity (operating and operable shutdown) was 12.9 million barrels/day. The following table shows the breakdwon of this capacity by PAD District. Actual crude runs in 1970 were 10.9 million barrels/day. 1/

PAD District	Capacity (million barrels/day)
I	1.5
II	3.7
III	5.3
IV	0.4
V	2.0

1/ NPC, p. 280.

In analyzing future refinery requirements, a maximum case can be identified. The maximum case would be to meet demand for petroleum products with supplies run through U. S. refineries. All imports would, therefore, be crude oil. Crude runs in 1980 would be about 20.9 million barrels/day, and in 1985, 25.0 million barrels/day. This would mean an increase in crude runs of 10.0 million barrels/day by 1980 and 14.1 million barrels/day by 1985 over the actual 1970 levels.

The minimum refinery requirement would be to provide just enough capacity to process domestic production. In this case all imports would be in the form of petroleum products and petrochemical and SNG feedstocks. Crude runs would be 11.8 million barrels/day in 1980 and 11.6 million barrels/day in 1985. Both of these figures are less than 1971 total capacity, but greater than actual crude runs in 1970. The retirement of old and obsolete facilities would require the construction of some new capacity through 1985. 1/

Recognizing that, for economic and security reasons, the United States should not rely on petroleum products imports, President Nixon created incentives for the expansion and construction of

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1/ NPC, p. 280.

refineries to process foreign crude. Under the new import system, companies building new refineries or petrochemical plants, or expanding present facilities, will be granted fee-exempt allocations of imported oil equal to 75 percent of their additional inputs for the first five years of operation. These exempt allocations would be in addition to any fee exemptions which the company had already received.

ECONOMIC REQUIREMENTS

The total capital costs of the tankers required to carry future imports will depend on the size tanker which is employed. The NPC has estimated that, assuming the use of vessels averaging 250,000 DWT, over 400 tankers would be required. At a cost of $36 million each (currently quoted for foreign construction) there would be total capital requirements, in terms of 1970 dollars, of $14 billion by 1985. The assumption was made, however, that all waterborne imports would be coming from the Persian Gulf. For every million barrels/day from North or West Africa, the investment in tankers could be reduced by $0.6 billion. Thus if one to two million barrels/day comes from Africa, capital investment would be about $13 billion. 1/ There would also be a reduction for waterborne imports originating in the Western Hemisphere. The $13 billion to $14 billion represents,

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1/ NPC, p. 283.

therefore, a maximum value. The NPC estimates that additional terminal and transportation costs will require capital investment on the order of $2 billion (1970 dollars) through 1985. 1/

Any expansion of United States refinery capacity will require capital investments. Providing the maximum refinery capacity through 1985 would require an increase in crude runs of about 14 million barrels/day. This would necessitate the construction of 15 to 16 million barrels/day of net new refinery capacity at a capital cost of about $30 million (1970 dollars). 2/ The minimum refinery case could be met with existing capacity. There would, however, still be significant capital requirements for the replacement of old or obsolete equipment.

Balance of Payments

Petroleum imports and asociated activities have been an important factor in United States balance of payments. Imports of oil and refined products in recent years have equalled, in value, roughly 7 percent of all imports. The petroleum industry has accounted

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1/ NPC, p. 295.

2/ NPC, p. 280.

for approximately 25 percent of U. S. net capital outflows and 33 percent of U. S. net earnings abroad. 1/ Table VII-2 shows the balance of trade in energy fuels for 1970, 1975, and 1985. These estimates are based on their Case III situation.

	1970	1975	1985
Oil Imports (Delivered) 2/	-3.4	-12.9	-20.4
Natural Gas and LNG Imports	-0.2	- 0.5	- 5.3
Total Energy Fuels Imports	-3.6	-13.4	-25.7
Oil Exports	+0.5	+ 0.4	+ 0.4
Steam Coal Exports	+0.1	+ 0.2	+ 0.3
Metallurgical Coal Exports	+0.9	+ 1.3	+ 2.1
Total Energy Fuels Exports	+1.5	+ 1.9	+ 2.8
Balance	-2.1	-11.5	-22.9

Source: NPC, p. 298 and p. 302.

One of the major assumptions used by the NPC was that the f.o.b. oil prices in 1975 and 1985 will be no higher than projected 1975 prices under currently existing contracts. The recent devaluation of the dollar will result in increased import prices. As a result of monetary changes the Organization of Petroleum Exporting Countries (OPEC) has asked for a 10 to 15 percent increase in contract prices. The petroleum companies involved have offered a 6-7 percent increase. At present, the situation is too unsettled to make an accurate estimate of the effect on U. S. balance of payments.

1/ NPC, p. 297.

2/ Including synthetic gas feedstocks.

Another important factor in balance of payments is the secondary trade stimulated by the purchases of petroleum. U. S. dollars which are used to purchase fuel or to finance overseas operations will generate return flows when the energy exporting country spends part of its increased income on U. S. goods and services. These return flows may come directly from the first recipient of the U. S. dollars or indirectly through third or fourth party countries. In balance of payment considerations, the direct first-round returns are most important. The level of first-round return flows from an exporting country can be estimated by the country's average propensity to import from the United States. The propensity to import factor indicates what portion of each dollar can be expected to return in direct purchases of U. S. goods and services in the short-term. Table VII-13 shows the average propensity to import from the U. S. of major oil exporting nations. It should be noted that as the primary source of imports shifts from the Western Hemisphere to Eastern Hemisphere, the first-round return on each dollar will decrease.

SECURITY CONSIDERATIONS

In 1970, a comprehensive study of oil imports was done by the Cabinet Task Force on Oil Import Control. The Task Force's

Table VII-13

Average Propensities to Import from the United States 1/

Algeria	0.062
Indonesia	.146
Iran 2/	.178
Iraq	.111
Kuwait	.208
Libya	.166
Nigeria	.116
Saudi Arabia	.291
United Arab Republic 2/	.514

Source: U. S. Department of Interior, An Analysis of the Economic and Security Aspects of the Trans-Alaska Pipeline, Vol. I, p. F-8, (December, 1971)

report, entitled The Oil Import Question, identified eight major security difficulties that might attend dependence on foreign supplies.

> "(1) War might possible increase our petroluem requirements beyond the ability or willingness of foreign sources to supply us.
>
> (2) In a prolonged conventional war, the enemy might sink the tankers needed to import oil or to carry it to market from domestic production sources such as Alaska.

1/ Directions of trade, IMF. Averaged over trade data for 1962-67. No clear trends were discernible, hence the recent average may be taken as an adequate approximation to the marginal propensity.

2/ A significant fraction of the trade of Iran and the U.A.R. with the United States is financed by U. S. sources. Consequently, the balance-of-payments effect of U. S. trade with both countries is reduced by partly compensatory transactions on capital account.

(3) Local or regional revolution, hostilities, or guerilla activities might physically interrupt foreign production or transportation.

(4) Exporting countries might be taken over by radical governments unwilling to do business with us or our allies.

(5) Communist countries might induce exporting countries to deny their oil to the West.

(6) A group of exporting countries might act in concert to deny their oil to us, as occurred briefly in the wake of the 1967 Arab-Israeli War.

(7) Exporting countries might take over the assets of American or European companies.

(8) Exporting countries might form an effective cartel raising oil prices substantially." 1/

With the creation of OPEC, the last point, formation of an effective cartel, has already occurred. The result, as the study has forseen, has been a substantial increase in oil prices.

The basic problem with importing a substantial fraction of the Nation's oil is that the sources of additional foreign oil--in general, the Middle East, and North Africa--are "insure", and might withhold oil exports to the United States for political and/or economic gain.

1/ Cabinet Task Force on Oil Import Control, The Oil Import Question, (February, 1970) p. 31.

A study by Drs. Schurr and Homan for Resources for the Future 1/ notes that the question of supply interruptions:

> ". . . needs to be dealt within the interests of both the importing and exporting countries because supply interruptions are economically damaging to both. Not only do they have sharp short-run effects which are economically painful, but their longer-run consequences can also be damaging if channels of commerce are diverted into alternatives which impose a permanent economic penalty upon both those countries that sell oil and those that buy."

However, this interdependence does not guarantee that interruptions will not occur. The study points to interruptions from the shutdown of Iranian production beginning in 1951, the closure of the Suez Canal and attendant lengthening of transportation routes in 1956-1957 and again from 1967 to the present.

The Oil Import Question identified three possible types of alternative measures to cope with an interruption of supply. These are: using synthetic sources of crude, such as oil shale or tar sands; developing the shut-in capacity of Naval Petroleum Reserve No. 4; providing a means of storing oil. The potential of synthetic sources of crude oil and the NPR #4 reserves are discussed in other parts of this document. The most promising methods of storing oil are in steel tanks or in salt domes.

1/ Sam H. Shurr and Paul T. Homan, et.al., Middle Eastern Oil and the Western World: Prospect and Problems. New York, American Elsevier, 1971.

Estimates made in 1970, of the capital costs of storage in steel tanks range from $1.84/barrel to $2.75/barrel, including land acquisition. Annual management and repair costs would be 11-14 cents/barrel. Evaporation losses in a cone roof tank would be about 2 percent. However, if a floating roof were used, evaporation losses should be neglible. 1/

In the United States, salt domes are presently used for the storage of natural gas liquids. A 1966 study by the Department of the Interior indicated that there were, at that time, 130 unused onshore salt domes suitable for storage in the Gulf Coast area. 2/ The Interior Department assumed a potential storage capacity of five million barrels at each site, yielding a total capacity of 650 million barrels. The capital cost of salt dome storage was estimated to be $1.02/barrel to $2.04/barrel. Because there is no evaporation loss and only minor maintenance and management costs, total annual costs would be low. There would be some loss of oil in the recovery process. The Interior Department assumed a five percent loss in ultimate recovery. 2/

1/ Oil Import Question, p. 299.

2/ Bureau of Mines, "Salt Domes in Texas, Louisiana, Mississippi, Alabama, and Offshore Tidlands: A Survey, 1966" (IC 8313).

3/ Oil Import Question, p. 301.

Proposals have been made to establish a national petroleum reserve to guard against interruptions in the supply of foreign oil. These proposals would involve establishing storage areas, requiring holders of federal oil and gas leases to maintain excess capacity by producing at less than their maximum efficient rate, and the setting aside of certain areas for petroleum reserves. The Santa Barbara Channel OCS has been suggested as a possible petroleum reserve area.

The establishment of a national petroleum reserve would require an increase in imports in the short-run. These imports would either go directly into storage or replace domestic crude oil which would be stored or held in reserve.

ENVIRONMENTAL IMPACT

The consideration of environmental impacts in this analysis primarily related to additional ship traffic and oil handling associated with the increased level of imports.

Potential Oil Pollution

Three factors are considered in analyzing possible oil pollution related to tanker shipment of imports: (a) intentional discharge, (b) accidental discharge and (c) casualty analysis.

Intentional Discharge

The two primary sources of intentionally discharged oil are shoreside ballast treatment facilities and underway tank cleaning operations. 1/ Any development of ballast treatment facilities would be accomplished at the loading end of the system. It may be assumed that all intentionally discharged oil in U. S. waters from this alternative will come from tank cleaning operations.

To assess fully the impact of tank cleaning operations, three separate analyses are necessary. While the overall average discharge rate in 1969-1970 was 0.074 percent of cargo, uncontrolled operations averaged 0.46 percent, load-on-top (LOT) averaged 0.027 percent, and the IMCO standard proposed in the 1969 amendments to the 1954 Intentional Convention for the Prevention of Pollution of the Sea by Oil was 0.0067 percent (one part in 15,000). Oceanborne imports in 1975 are expected to be 4.1 million barrels/day; in 1980, 6.1 million barrels/day; and in 1985, 10.7 million barrels/day. The following table shows the expected oil spill levels under the three conditions:

1/ USDI, Trans-Alaska Pipeline System, Environmental Impact Statement op.cit.

Potential Intential Oil Spill Levels (thousand barrels/day)

	Oceanborne Imports	Uncontrolled Operations	L.O.T. Operations	IMCO Standards
1975	4100	18.9	1.1	0.3
1980	6100	28.1	1.6	0.4
1985	10700	49.2	2.9	0.7

Accidental Discharge

The 1970 Pollution Incident Reporting Systems (PIRS) data indicate that approximately 0.0015 percent of the oil handled in the U. S. was spilled during transfer operations. 1/ Applied to the projected throughput for 1975, 1980, and 1985, this would indicate spills of 61 barrels/day, 91 barrels/day, and 160 barrels/day respectively.

In the restricted waters surrounding harbors and ports, the 1970 experience indicates that about 0.00009 percent of the oil handled is accidentally discharged. 2/ This would indicate spills of 3.7 barrels/day in 1975, 5.5 barrels/day in 1980, and 9.6 barrels/day in 1985.

1/ U. S. Coast Guard, "Marine Transport Systems of the Trans-Alaska Pipeline System", 1972.

2/ Ibid.

Casualty Analysis

The worldwide tanker casualty analysis indicates that an insignificant amount of the total volume of oil transported is spilled, exclusive of transfer operations. 1/ The environmental impact could be nominal where small spills are involved or where the spill occurs in such a manner as to have little impact on coastal or restricted water areas. By contrast, a single catastrophic incident such as the breakup of the Torrey Canyon can have disastrous results. The oil spill problem is a subject involving considerable study effort. The first report of the President's Panel on Oil Spills presents considerable details relative to the subject.

Increased Tankers and Terminals

Increased petroleum imports will require an increase in the number and/or size of tankers. The heavily populated Northern Atlantic coastal region will be the primary destination of petroleum shipments with the Gulf Coastal region being the secondary location. If the use of convential ports continues, tankers will generally be restricted to 60,000 DWT or less. As shown earlier, the continued use of these small tankers will require

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1/ USDI, Trans-Alaska Pipeline System, op.cit.

a significant increase in the number of tankers to be unloaded each day. This added congestion would increase the risk of collision and subsequent oil pollution. The transfer of oil from VLCC's to small tankers at foreign ports would also cause substantial increases in ship traffic. The problems of port congestion could be alleviated through the use of large tankers making deliveries directly to U. S. terminals.

The environmental impacts of a terminal to handle large tankers will be determined by its location. Enlarging the channels and harbors of existing ports would require dredging which could endanger sensitive estuarine areas. These areas are important as nursing grounds for many species. Extensive dredging also presents the danger of penetrating freshwater aquifers and causing saltwater contamination of a major city's water supply. Expansion of existing port facilities in populated areas could cause conflicts with existing or planned land uses.

Offshore terminals would greatly reduce the dangers of dredging and port congestion. The determining factor would be the facilities' distance from shore. Terminals which are sited closer to shore will generally require a greater amount of dredging. Such a facility could, therefore, cause some damage to estuarine areas as a result of dredging and from oil spills which could reach shore before dispersing or being cleaned up. A terminal further offshore could obviate the need for dredging and allow spills to disperse or be cleaned up before reaching sensitive areas.

The construction of a breakwater or island will permanently eliminate from productivity the area of seafloor and volume of water it occupies. Some of this loss will, however, be offset by fish havens formed by the rubble mounds and structures. A deeper offshore setting would again be preferable because it would affect fewer species. A breakwater could reduce wave action at the shoreline and thereby reduce erosion of the beach. This could lead to the deposition of suspended sediments and accretion of the beach. Continued accretion could cause the development of a sand spit, which may ultimately extend to the offshore structure. If this accretion were located at the upper end of the beach system, the normal supply of sand would be cut off and erosion of the beach would occur. Generally, if the distance from shore is more than twice the length of the structure, the effect on the shoreline would be minimal. 1/

1/ Maritime Commission, Executive Summary, p. 19.

Pollution Potential at Loading Site

The increased movement of petroleum will also result in increased oil spills at the loading end. These spills will, as at the receiving end, result from intentional and accidental discharges and tanker casulties, such as collisions, groundings, etc.. In some exporting countries pollution control standards may not be as stringent as United States standards, and thus there may be a greater potential for pollution at some loading sites.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

Under this alternative, the replacement of the total energy expected from this sale would require additional oil imports of 331,000 to 536,000 barrels a day. If 29,000 DWT tankers were used (the average size tanker calling at U. S. ports in 1972), there would be two to three additional tanker unloadings each day. If 60,000 DWT tankers were used (the maximum size tanker which can presently enter U. S. ports), one to two additional tankers would have to be unloaded each day.

The imported oil would go predominantly to the North Eastern U. S., with a small amount possibly going to the Gulf Coast region. This oil would probably come from Middle Eastern or African sources.

Importing petroleum would have a negative impact on the United States balance of payments. Some of the factors affecting this impact are: the type of import, i.e., crude oil, semi-refined products, or refined products; the price of imported oil; the exporting countries' propensity to import from the U. S.; the amount of U. S. capital invested in the exporting country for production, transportation and terminal facilities, and the amount of U. S. goods and services used in the exporting country for these facilities; and the nationality of vessels carrying the oil. In the past, imported petroleum was generally less expensive than domestically produced petroleum. Recent events, such as the devaluation of the U. S. dollar and agreements which allow greater participation of the exporting countries in oil production, have brought the price of foreign oil delivered to the U. S. to a level equal to or greater than that of oil produced on the OCS.

The primary environmental hazard of increased oil imports is the possibility of oil spills. Spills can result from intentional discharge, accidental discharge, and tanker casualties. Intentional discharges would result largely from tank cleaning operations, which in 1969 to 1970 had an overall discharge rate of 0.074 percent of cargo. At this rate, import levels of 331,000 to 536,000 barrels a day would result in discharges of 245 to 397 barrels a day. In 1970 approximately 0.0015 percent of oil handled in the U. S. was accidentally released during transfer operations. At this rate, 5 to 8 barrels a day would be accidentally spilled. The worldwide tanker casualty analysis indicates that, overall, an insignificant amount of the total volume of transported oil is spilled due to tanker accidents. However, a single incident such as the breakup of the Torrey Canyon can have disastrous results. With increasing tanker traffic in already crowded harbors, the probability of such an incident is increased.

b. Natural Gas Imports

As shown in Section IA of this report, domestic production of natural gas will have to be supplemented in order to fulfill demand. These supplements will come in the form of synthetic gas from coal and/or liquid hydrocarbons or as imports. Synthetic gas has been discussed in Section IV. Natural gas imports could come into the United States via pipeline from Canada or Mexico or as tanker-borne liquefied natural gas (LNG) from other countries.

PIPELINE NATURAL GAS IMPORTS

Pipeline imports of natural gas into the United States have come from the two bordering countries of Canada and Mexico. In 1972, 1.0 trillion cubic feet were imported, via pipeline, from Canada, while 0.008 trillion cubic feet came from Mexico. There is little prospect for increased imports from Mexico. A relatively small proven natural gas supply base and a policy of "self-sufficiency in energy" indicate that potential new gas will probably not be available for export. Present contracts expire in 1982; thus if no new supplies of gas are released for export, significant natural gas imports from Mexico could cease at that time. 1/ Future increases in pipeline imports of natural gas will, therefore, have to come from Canada.

1/ Federal Power Commission, Bureau of Natural Gas, National Gas Supply and Demand 1971-1990 Staff Report No. 2, Feb. 1972, p. 57, also Tables 25 and 26, p. 140.

Based on actions by the Canadian National Energy Board (NEB), it appears that future increases in natural gas exports from Canada may be limited. In November, 1971, the NEB dismissed three applications for licenses to export over a 15 to 20 year period nearly 2.7 trillion cubic feet of gas to the United States. The NEB rejected the applications because "---the Board decided that there was no surplus of gas remaining after due allowance had been made for the reasonably foreseeable requirements for use in Canada---." 1/

The NEB's determination that there was no surplus of gas was based on the method used for calculating the required supply. The Board makes determinations of both current and future natural gas supply when considering export applications. Under NEB requirement the current gas supply should be adequate to meet authorized deliveries under existing export licenses as well as current Canadian domestic demand for almost 30 years. On this basis, in 1971, there was a supply deficiency of 1.1 trillion cubic feet. The future supply must be adequate, based on a given level of annual reserve additions, to protect existing export licenses and to maintain a reserve to production ratio of approximately 30 for Canada's projected domestic requirements for 20 years into the future. If

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1/ Canadian National Energy Board's Annual Report, December 31, 1971.

projected gas supply exceeds projected supply requirements, an exportable surplus results. FPC calculations based on the historical finding rate of 3.5 trillion cubic feet per year, show that supply could fall 23.4 trillion cubic feet short of these requirements. [1]

Recent discoveries in the Arctic Islands, Mackenzie Valley, and Atlantic offshore regions will eventually, however, result in larger reserves additions. The NEB will not consider these new discoveries in its reserve calculations until they have been developed sufficiently to be within economic reach. If the discoveries continue and are developed, major surpluses may become available for export by the end of this decade.

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[1] FPC, p. 51.

Table VII-14 shows various projections of pipeline imports from Canada.

Table VII-14

Pipeline Imports from Canada
(Trillion cubic feet)

	1975	1980	1985
FPC 1/	1.2	1.6	1.9
Interior 2/	2.0	3.0	4.1
NPC 3/	1.0	1.6	2.7

The environmental impacts of pipeline construction and operation have been discussed in Section II-A. The impacts of pipelines carrying gas from Canada and Mexico would be essentially the same.

1/ Federal Power Commission, p. 55.

2/ Department of the Interior, U. S. Energy Through the Year 2000, p. 45, (Includes Mexican Imports).

3/ National Petroleum Council, *U. S. Energy Outlook*, p. 267.

LIQUEFIED NATURAL GAS (LNG) 1/ IMPORTS

Projections of Import Levels

Because of the growing shortage of domestic gas supplies, plans are now being made by the gas industry for baseload LNG imports under long-term contracts. LNG imports cannot, however, simply be increased to meet the demands for greater supplies of natural gas. Large scale shipping of LNG is a relatively new industry and the United States does not yet have facilities for receiving baseload shipments. The FPC recently approved two projects which together call for deliveries of the equivalent of more than 1 billion cubic feet/day of LNG. Several other projects have been proposed and are pending approval. Future import levels will, therefore, be dependent on the rate of buildup of the United States' LNG industry. The following table shows various projections of LNG imports.

1/ Natural gas becomes a liquid at -259°F at atmospheric pressure.

Table VII-15
(Trillion Cubic Feet)

	1975	1980	1985
FPC 1/	0.3	2.0	3.0
Interior 2/	0.5	0.9	1.6
NPC 3/	0.24	2.28	4.11

Source and Destination of Imports

In 1971, non-Communist natural gas proved reserves were estimated to be 1,033 TCF and production was 138 TCF. The estimate of future discoverable reserves was 6,167 TCF. 4/ It appears, therefore, that sufficient supplies of natural gas will be available for export to the United States. Table VII-16 shows NPC's estimate of maximum LNG imports and a breakdown by source country. The second column shows the calculated backup of reserves necessary to support the estimated level of exports to the U. S. (based on 12.5 billion cubic feet of reserves for each million cubic feet per day of export) and the third column shows proved reserves as of January, 1971. Even without further discoveries these countries appear to have sufficient reserves to support exports to the United States.

1/ FPC, p. 70.

2/ USDI, p. 45.

3/ NPC, p. 286.

4/ NPC, p. 264.

Table VII-16

1985 LNG IMPORT PROJECT SUPPLY

Country	LNG Projects (MMCF/Day)	Calculated Reserve Backup (TCF)	1/3/71 Reserve Estimate
Algeria	4,350	54.4	106.5
Nigeria	3,500	43.8	40.0
Venezuela	1,000	12.5	25.4
Trinidad	300	3.8	5.0
Ecuador	500	6.3	6.0
Pacific	1,000	12.5	42.9

Source: NPC, p. 266.

The one base load project which has been approved by FPC will obtain LNG from Algeria and deliver it to the U. S. East Coast (Cove Point, Maryland and Savannah, Georgia.) As indicated in the table above, supplies will be obtained from countries in all parts of the world. LNG receiving points will be primarily located on the East Coast, with other projects on the Pacific and Gulf Coasts.

TECHNOLOGICAL PROCESSES

The primary advantage of liquefying natural gas is the more than 600 to one volume reduction which results. LNG was first used by gas utility companies for peak shaving and satellite facilities and for remote and emergency deliveries. With the development of technology for marine transportation of LNG, large new sources of natural gas have become available to the United States.

Several processes exist for liquefying natural gas. Two primary methods are: 1) the transfer of heat through separate refrigerants to air or water; and 2) permit the gas to do work through the use of an expander. The first method, known as a cascade cycle, utilizes refrigerants of successively lower boiling points. The second method, known as an expander cycle, utilizes the cooling effect obtained by expanding a stream of compressed gas through a turbine or engine to extract work. 1/

Insulated storage is required for the LNG both after it has been produced and before it is regasified. The most frequently used storage tanks for base load operations have been above ground, double-wall metal tanks. The space between the walls

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1/ NPC, p. 63.

is filled with insulation, a partial vacuum or both. Prestressed concrete tanks have been used for other cryogenic fluid storage and may be applied to LNG. Testing has shown that the compressive strength of moist concrete at -150°F to -250°F is almost triple that of concrete at room temperature. [1]

There are at least four configurations for LNG ocean tankers. The "freestanding" system utilizes self supporting tanks which rest in the ship's hold and are independent of the hull. Insulation of this type is either on the outside of the tanks or the inside of the ship's hull. The membrane type uses the ship's hull as the tank wall with insulation attached to the hull. Another system incorporates five spherical cargo tanks, which are designed to reduce cost by requiring less insulation. All the above systems usually carry LNG at atmospheric pressure. Another tanker concept would carry medium condition liquefied gas (MLG) in cargo bottles at a temperature of -175°F and 200 Psig.

LNG is regasified by circulation through tubes. The heat for the process is obtained from the surrounding air or water, or is produced by the combustion of a fuel, such as some of the natural gas itself. After LNG has been regasified it can be introduced into conventional natural gas pipeline systems.

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[1] NPC, p. 65.

Economic Considerations

Table VII-17 gives an indication of the capital costs which will be involved in the importation of LNG. Also shown in the table are potential source and destination points, import volumes, and the number of tankers required. Additional capital will be required for pipelines to connect the regasification plants with existing pipelines. This cost will be dependent on the location of the plant and of the pipeline. Pipeline construction for the Cove Point plant will require $89 million, while pipelines for the Savannah plant will cost $25 million. 1/

LNG imports will also have an impact on United States balances of payments. At this point in the development of the program it is difficult to determine what this impact will be. Capital from the United States will undoubtedly be involved in the construction of liquefaction plants. The Export-Import Bank, for example, is providing some of the funds necessary for the construction of an Algerian plant. It has not been established, however, just how much U. S. capital, will move to exporting countries or how much money will return through the purchase of U. S. equipment. The use of foreign or domestic tankers will

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1/ Federal Power Commission, Docket No. CP 71-68.

also be a factor in the balance of payments. The cost of the gas itself will, however, probably have the greatest influence on balance of payments. One estimate of the f.o.b. price of gas is 38¢ to 53¢/Mcf. 1/ Importing 1 Tcf could, therefore, result in an outflow of $380 to $530 million. It should be noted that the various potential source countries represent a wide range of propensities to import from the U. S. (see Table V-13 in previous section).

The price to the consumer of imported LNG is also difficult to project. The FPC, in approving the El Paso Natural Gas Co. application to import LNG, limited initial prices to 77¢ per million BTU's delivered to Cove Point, Md. and 83¢ at Savannah, Ga. The company has indicated that the allowed prices may be insufficient. The current prices for natural gas in the United States, under the area rate method, range from 22.5 to 34.0¢/Mcf at the wellhead. Under the FPC's new optional pricing system the price of new gas is higher. The first applications under this policy have proposed to sell gas for prices up to 55¢/Mcf.

1/ Amanullah R. Khan and William W. Bodle, "Supplementing United States Gas Supplies With Imported LNG," Journal of Petroleum Technology, May, 1972.

Table VII-17

LNG CAPITAL REQUIREMENTS FOR LIQUEFACTION, TRANSPORTATION AND REGASIFICATION—ALL CASES

(Millions of Constant 1970 Dollars)

	Voyage Route			Round Trip		Capital Requirements Millions Dollars			
Period	**Source**	– **Delivery Point**	**Quantity BCF/Day**	**Nautical Miles**	**Ships Required**	**Ships**	**Liquefaction Plant**	**Unloading Terminal**	**Total Capital**
Last Half 1975 1/	Algeria	– Cove Point	.350	7,300	3	150	131	49	230
	Total by End of 1975		**.350**		**3**	**150**	**131**	**49**	**230**
Additional 1976 – 1980	Algeria	– Cove Point	.300	7,300	2	117	120	54	291
		– Savannah	.500	7,900	4	220	175	56	451
		– Delaware River	.900	7,200	6	349	291	66	706
		– New York	.300	6,900	2	114	120	53	287
	Nigeria	– Delaware River	.650	9,800	6	337	222	60	619
		– New York	.200	9,700	2	106	91	46	243
		– Chesapeake Bay	.350	9,800	3	176	131	56	363
		– Boston	.300	9,500	3	158	120	50	328
	Venezuela	– Delaware River	.500	3,900	2	118	175	59	352
		– Lake Charles	.500	3,800	2	116	175	59	350
	Trinidad	– Lake Charles	.300	3,800	2	85	120	43	248
	Alaska	– Portland	.300	2,800	2	106	120	40	266
	Ecuador	– Los Angeles	.500	6,500	3	117	175	59	411
	Total Additional 1976-1980		**5.600**		**39**	**2,179**	**2,035**	**701**	**4,915**
Additional 1981 – 1985	Algeria	– New York	.500	6,900	3	183	175	61	419
		– Delaware River	.250	7,200	2	104	104	48	256
		– Chesapeake Bay	.500	7,300	4	211	175	55	441
		– Boston	.250	6,600	2	100	104	46	250
		– Savannah	.250	7,900	2	110	104	50	264
	Nigeria	– New York	.500	9,700	4	245	175	61	481
		– Delaware River	.500	9,800	4	248	175	61	484
		– Chesapeake Bay	.250	9,800	2	124	104	55	283
		– Boston	.250	9,500	2	121	104	54	279
		– Savannah	.250	9,900	2	124	104	55	283
	Pacific	– San Francisco	.500	13,200	6	341	180	58	579
		– Los Angeles	1.000	13,000	11	659	329	68	1,056
	Total Additional 1981-1985		**5.000**		**44**	**2,570**	**1,833**	**672**	**5,075**

Source: NPC, p. 294

1/ Due to delays in licensing, the 1975 delivery level may not be achieved.

Environmental Impacts

The environmental impacts in the United States of LNG imports would be those of (1) tankers, (2) terminal, transfer, and regasification facilities, and (3) transportation and combustion of the gas.

Tankers

Any seagoing vessel may be involved in collision or other mishap. However, escape of LNG to the environment would not necessarily result in significant impact. Since LNG remains liquid only at -259°F at atmospheric pressure any spilled LNG would immediately begin to vaporize and, although it would pollute the air, would have little impact on land or water resources. Studies on the possibility of violent reactions upon contact between LNG and water resulting from LNG spills are inconclusive. Tests conducted during 1969 produced several instances of violent reactions upon contact between LNG and water. No fire or ignition of vapor was observed, but there was a rapid upward movement of gas accompanied by a loud "bang". 1/ A later study concluded that there was little danger of a violent reaction between normal LNG and water, and that such a reaction could result only after the methane content of the LNG had reached 40 percent. Since the normal methane content

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1/ USDI, Bureau of Mines, "Hazards Associated With the Spillage of Liquefied Natural Gas on Water", Nov. 1970, p. 23.

of LNG is 80-90 percent or more and the boil-off rate is 0.2 percent per day, a reduction to 40 percent is not likely under current shipping practices. [1] In the case of a large spill, the quantity of LNG remaining after weathering into the critical composition range could be significant. However, during the weathering period, the LNG will have spread on the surface and the chance of a single large reaction is relatively small. Since no chemical reaction is involved the energy available for a reaction is limited to the amount of super heat achieved during the time of direct liquid-liquid contact.

Transfer and Storage

Each regasification plant will require facilities to permit the transfer of LNG from tankers to storage areas. In the Cove Point case, this will be accomplished by the construction of a milelong pipeline into the Chesapeake Bay. At the proposed Savannah plant a channel and a turning basin would be dredged in the Savannah River to allow the tankers to come close to the plant. Both of these methods will require initial dredging, and possibly continued dredging, causing increased turbidity of the water and disruption of marine animals, especially in the case of bottom dwelling organisms. In most cases this disruption would be temporary, but care would have to be taken to avoid, as much as possible, commercial fishing areas. The potential for fire or explosion is always present during the transportation, transfer, or storage of LNG. Since spilled LNG would not vaporize instantaneously, the release of the equivalent of several million cubic feet of gas, for example, might cause a fire which could continue until all the LNG had vaporized. An early LNG plant was destroyed by a disastrous fire in 1944 due to the failure of a storage tank, with a loss of more than one hundred lives. Since then, many improvements have been made in the technology of storage and handling of the LNG and increased attention has been given to proper safety precautions. The recent explosion of a Staten Island storage tank, killing more than 40 men, shows that there is still, however, an element of danger involved in the storing and handling of LNG.

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[1] Tholief Enger, "Rapid Phase Transformation During LNG Spillage on Water," paper presented before The Third International Conference and Exhibition on Liquefied Natural Gas, September 1972.

Regasification

The construction of regasification plants will have an impact on land resources. The extent and duration of the impact will depend on the size and location of the plant. For example, the plant proposed for Cove Point, Md., would produce initially 650 million cubic feet per day and require a 1,022 acre tract of land; another plant proposed for Savannah, Georgia, would produce initially 335 million cubic feet per day and require 860 acres, or 1.5 to 2.5 acres per mmcf capacity. During construction there will be some disruption of the land surrounding the plant, and some damage to animal habitats. This damage will be permanent only in the area occupied by the plant and supporting facilities.

Since natural gas or water will be used to regasify the LNG, very few pollutants will be released to air or water. Plants using water to regasify LNG will release the water at a lowered temperature. In the case of the Savannah plant, water temperature will be lowered 5°F before being returned to the river.

A regasification plant could have an impact on the scenic and recreational resources of an area. The choice of the plant site is an important factor in minimizing the impact on scenic qualities and recreational activities. The increase in ship traffic could have an effect on water-oriented recreational activities.

Impact of Combustion and Transportation

Since natural gas is a relatively clean burning fossil fuel, the impact on air quality would not, therefore, be significant. LNG imports will require the construction of new pipelines. The impact of this construction has been discussed earlier in relation to domestic production of natural gas.

RELATIONSHIP OF ALTERNATIVE TO PROPOSED OCS SALE

This alternative would require natural gas imports of 1,86 to 3.01 billion cubic feet/day (0.68 to 1.10 trillion cubic feet/year) to replace the total energy expected from this sale. Projections of future natural gas import levels indicate a maximum level of natural gas imports of 3.9 trillion cubic feet/year in 1980 and 6.8 trillion cubic feet/year in 1985.

Any increases in pipeline natural gas imports would have to originate in Canada. At the present time, the policy of the Canadian government has been to restrict the level of gas exports in order to build a large domestic reserve. Unless there is a change in this policy, it is unlikely that the necessary gas would be made available.

Increases in LNG imports will depend on how soon this industry can be introduced into the U. S. At the present time there are no baseload LNG projects in operation in the U. S., although one has been approved and others are pending approval. To supply the energy expected from the sale with LNG imports would require the unloading of about one 125,000 cubic meter tanker every day and the construction of five to nine 350 million cubic feet/day regasification plants.

8. Other Energy Sources

The basic nature and occurrence of any energy source largely govern the technological opportunities and problems involved in its application. As research continues probing into the nature of numerous energy sources, many potential alternatives to conventional energy production are emerging. The existence of some of these sources has been known for decades, although unfavorable economics or incompletely developed technologies have hampered their commercial acceptance. Long range projections must take into account such potential sources of energy, since a major technological breakthrough in any number of areas could effect a considerable change in the current energy picture.

Environmental impacts of these more exotic alternatives are difficult to assess, particularly where there is a great amount of research and development that must be done before operational scale systems can be developed, tested, and evaluated for production application.

Lack of resources (due either to geographic location or lack of quantity and quality), underdeveloped technology, or lack of an economic advantage over conventional energy sources are the chief reasons these other sources are unlikely to have significant availability before 1985. Below are summarized the various energy forms considered here in relation to their primary and secondary limitations.

I. Possible significant energy contribution before 1985

Energy forms	Primary limitations	Secondary limitations
Geothermal Energy	Resources	Economics
Tar Sands	Resources	Economics

II. Improbable significant contributions before 1985 1/

Energy forms	Primary limitations	Secondary limitations
Hydrogen	Economics	Technology
Biological (agricultural & wastes)	Economics	Resources
Solar	Technology	Economics
Tidal	Resources	Economics
Wind	Resources	Economics
Energy Conversion Devices		
Fuel cells	Technology	Economics
Thermonics	Technology	Economics
Thermoelectric	Technology	Economics
Magnetohydrodynamics	Technology	Economics

1/ After: New Energy Forms Task Group 1971-1985 National Petroleum Council Committee on U. S. Energy Outlook, 1972.

In the Energy Message of April 18, 1973, the President proposed a 20 percent increase in energy research and development funding for fiscal year 1974. The 1974 budget also provides for the creation of a central energy fund in the Interior Department to provide additional money for non-nuclear research and development, with the greatest part designated for coal research. The following table shows the funds for different areas of energy research and the agencies involved.

Federal Energy R&D Funding
($ million)

	Agency 1/	FY'72	FY'73	FY'74
Coal				
Production and utilization R&D, incl. gasification, liquefaction, & MHD	DOI-OCR	30.3	43.5	52.5
	DOI-BOM	14.7	19.8	18.1
Mining health & safety research	DOI-BOM	28.5	31.2	28.3
Interior central fund (part)	DOI	-	-	21.0
Total		73.5	94.5	119.9

1/ Agency Codes:
AEC - Atomic Energy Commission
DOI - Department of the Interior
BOM - Bureau of Mines
GS - Geological Survey
OCR - Office of Coal Research
EPA - Environmental Protection Agency
NSF - National Science Foundation
TVA - Tennessee Valley Authority

Cont'd

Nuclear fission				
Liquid Metal Fast Breeder Reactor	AEC	236.0	269.0	320.0
	TVA	0.2	3.0	3.0
Other civilian nuclear power	AEC	86.8	98.0	90.5
Nuclear materials process development	AEC	35.0	42.0	61.9
Total		358.0	412.0	475.4
Nuclear fusion				
Magnetic confinement	AEC	33.3	39.6	47.3
Laser	AEC	19.5	25.9	41.2
Total		52.8	65.5	88.5
Solar Energy	NSF	1.7	4.2	12.2
Geothermal Energy	NSF	0.7	0.7	1.4
	DOI-GS	0.7	2.5	2.5
	DOI-BOM	-	0.2	0.2
Total		1.4	3.4	4.1
Electrical generation transmission and storage	NSF	1.3	2.4	0.9
	DOI	0.9	1.0	1.0
	AEC	-	1.5	2.2
Total		2.2	4.6	4.1
Petroleum & natural gas				
Petroleum extraction tech.	DOI-BOM	3.2	3.1	3.1
Nuclear gas stimulation	AEC	7.1	7.2	4.0
Oil Shale	DOI-BOM	2.6	2.5	2.0
Total		12.9	12.8	9.1

Cont'd

Control Technology				
(stationary sources)				
Air pollution control technology	EPA	24.5	29.5	21.5
SO_x removal	TVA	1.1	3.0	18.0
Thermal effects	EPA	0.7	1.0	1.0
	AEC	2.3	4.6	7.0
Total		28.6	38.1	47.5
Miscellaneous				
Systems and resource studies	NSF	4.4	5.3	5.3
Energetics research	NSF	1.9	1.6	1.7
Interior central fund (part)	DOI	-	-	4.0
Total		6.3	6.9	11.0
Total Federal Energy Research and Development		537.4	642.3	771.8

a. Long-Term Sources

1. Geothermal Steam

a) Description of the Alternative

Introduction

The development of geothermal and associated geothermal resources involves the harnessing of the natural heat energy sources in the earth for the generation of electric power, and the production of commercially valuable by-products.

The use of geothermal steam as a source of energy is still, in large part, in the investigative stages. Commercial geothermal production in the United States to date is small, existing in only one area in Geysers, California, and only since about 1960. Present exploration efforts are continuing mainly in the Imperial Valley, Morro Lake, Modoc County, California and Chandler, Arizona on private and public lands. There is currently no existing geothermal leasing program on Federal lands although proposals are under consideration. Developments in Italy have existed since about the turn of the century. Worldwide geothermal exploration and development in 1970 was limited to six fields with present capacity of about 1,000 MW. Development of geothermal resources is similar to oil and gas production operations except that it deals with water in the gaseous and fluid state, under pressure, produced from the earth through drilled holes. Operating plants for converting the steam to electrical energy consist of low pressure steam-turbine systems similar to those in use in the early 1920's. New technology should expand the use and adaptability of the resource beyond its current limitations.

In meeting future energy demand, the Nation must use many available sources of energy--coal, gas, oil, hydroelectric, and nuclear among the more important--and no one source is an exclusive alternative to any or all of the other sources. In this context, geothermal energy would hopefully be a feasible means of supplementing other forms of electric power generation on the local scale. Under present technology, and economics, and resource availability, however, geothermal cannot be expected to substitute for other forms of electric generation. Even under favorable assumptions, "United States Energy Through the Year 2000" (U.S. Department of the Interior, 1972) estimates that geothermal energy will comprise less than one percent of the national electric power capacity through the year 2000.

For a geothermal reservoir to have appreciable potential for exploitation, it must meet the following requirements: (1) relatively high temperature (greater than 150° to 400°F., depending on processing technology); (2) a depth shallow enough to permit drilling (currently 10,000 feet or less); (3) sufficient rock permeability to allow the heat transfer agent (water and/or steam) to flow continuously at a high rate, and (4) sufficient water recharge to maintain production over many years.

Geothermal reservoir systems can be categorized into either a vapor dominated system with a high yield of steam and little associated water, or hot water systems yielding only hot water which at high temperatures can flash to steam.

At the Geysers, geothermal steam electric capacity as of spring 1972 was 192 MW and an additional 110 MW came on line late in 1972, and 110 is subsequently scheduled in 1973, 1974 to reach a total of 552 MW. Beyond 1974, scheduled installation of at least 100 MW of new capacity per year could bring the production up to 1000-2000 MW which is the estimated ultimate capacity of the Geysers field. The success of this project is attributed to both favorable geologic conditions and heavy near-by demand for electrical generating capacity. The following table illustrates how this would replace an equivalent amount of oil needed. 1/

1/ Predicted geothermal power from National Petroleum Council, U.S. Energy Outlook, Vol. 2, 1971.

Table VIII

Oil requirement needed in Western United States to replace electricity generated by geothermal means (5.8 million Btu are assumed equivalent to 1 bbl. oil)

1971 OCS Production (oil + gas equivalency in Btu) = 914 mil. bbl. of oil

Year	Geothermal Power	Oil Replacement million bbl./year
1973	302 megawatts from Geysers Field, California	3.9
1980	1,000-2,000 megawatts from Geysers Field, California	13-26
1985	7,000-20,000 megawatts from all western U.S. sources (assuming new technology can be developed to use hot water).	91-260

Other favorable areas for prospecting exist on the Western United States. In California interest is chiefly in the Imperial Valley area and the Mono Lake-Long Valley area. Large amounts of land in Oregon, Washington, Idaho, and Montana are also classified as Known Geothermal Resource Areas (KGRA's). All of these areas are most likely hot water systems, rather than vapor dominated systems, and will require the disposal of large volumes of water creating additional environmental, technical, and economic problems before large scale development can proceed.

Production

Production of a geothermal resource involves exploration for suitable reservoirs, test drilling, production testing, field development, and power plant construction and operation.

Exploration for suitable reserves would involve topographic and geologic mapping, ground and spring temperature surveys, geochemical sampling, geophysical surveys, and finally shallow drilling to measure temperature, ground water flow, and sub-surface rock sampling. These exploration activities are surface-oriented investigations and therefore are subject to control as to potentially significant environmental damage by the nature of Federal leasing laws.

Test drilling is necessary to obtain sub-surface geologic data and thereby delineate the size, shape, physical and chemical properties of the reservoirs, and the nature of reservoir fluids. Current drilling methods are similar to those used in oil and gas operations, with some modifications. Both graded drilling sites and access roads would be needed to move the heavy drilling rigs, and supplies. During the drilling, provisions should be made for the control and disposal of drilling muds and fluids, prevention of blowouts, and containment of reservoir fluids, all of which have potential impact on the environment.

Production testing is the transitional phase between exploration and the development of potential production. A well that has penetrated a possibly productive geothermal zone is developed and tested over a period of time to both clean out the well and to determine a number of properties of the reservoir and fluids, i.e., flow rate, composition and temperature of the fluids, recharge characteristics, pressures and compressability. Sufficient time is necessary to establish various hydrodynamic properties and possibly boundaries of the reservoir. Venting of the fluids or vapors during this phase could have an impact on the environment. Fluids must be properly channeled into ponds separated from local water courses and steam vapors must be muffled by special mufflers or discharged underwater to prevent intolerable noise levels. If toxic substances are associated with the well effluent, they must be controlled and, of course, access roads as well as other construction activities involved in maintaining production testing sites would be necessary.

Field development would begin after favorable exploration test, drilling and production testing programs. A systematic pattern of wells would be drilled in order to maximize the output of the reservoir and to minimize individual well interference. The patterns adopted would reflect the interpreted characteristics of each reservoirs. The environmental considerations would be similar to the production testing phase with the exception that there would be more wells and they would be vented to a power facility rather than wasted to the earth's surface and atmosphere.

Power plant and power line construction involves commitment of large amounts of capital and would require successful completion of all the pre-production phases. Careful evaluation of environmental effects must be made prior to this large scale commitment of capital. Steam can practically be transported only about one mile and this involves above ground insulated pipes due to pronounced thermal expansions and contractions during operation. Underground pipe systems are uneconomical due to service and equipment requirements. If the effluent from a geothermal well is hot water, contaminants in that water must be removed before fresh water can be produced. If contaminants are not removed the effluent must be reinjected rather than discharged into the surface water system. Subsidence of the ground surface over and around a geothermal reservoir could result from depletion of large volumes of fluids. In raising fluids through various rock strata care must be taken not to contaminate a previously sealed fresh water aquifer. Materials used in the construction should be made of suitable corrosion resistant material to help prevent spills and leaks. Finally, construction and development would involve a commitment to deplete thermal energy and water from a geothermal reservoir; although renewable, it will take longer than the life of a specific project.

b) Description of the Environmental Impact

Potential Environmental Impacts [1]

The favorable impacts of geothermal power production, aside from the obvious socially desirable effect of supplying energy to the nation, include improved access and fire protection in an undeveloped country. Service roads to wells also provide access for hunters, fishermen, and for recreation in general. Fire control measures are improved such as clearing of brush and fire fighting in many terrains and also improved feed for birds and animals is provided.

Industrial Intrusion - The principal objection to geothermal power development stems from the intrusion of industrial development into new areas. Nearby residents and outdoorsmen generally find the noise, odor, and disturbance of terrain and vistas highly objectionable. Such objections are understandable, and operators have been attempting to meet them by alleviating the objectionable aspects insofar as practicable. However, some impacts are unavoidable and the public will have to decide whether the impacts are acceptable.

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[1] Final Environmental Impact Statement, Proposed Trans-Alaska Pipeline, Vol. 5, Department of the Interior, 1972.

Fish and Wildlife - Test drilling and production testing of geothermal steam resources would have varied impacts upon fish and wildlife. Most would occur on or adjacent to well sites, although water quality impacts could potentially have further influences. The magnitude of particular impacts would be interrelated with fish and wildlife and their habitat within the area of development influences, extent and duration of the entire geothermal development activities and operations, and the effectiveness of control measures. Many of the impact types lend themselves to whole or partial control.

As a specific geothermal development proceeds through test drilling and production testing, physical land modification and commotion would occur. These activities would include such things as contruction of roads, ponds, drill sites, and drilling of wells which would result in loss of wildlife values.

Most areas adjacent to drilling and test operations, but outside of the immediate zones of physical modification, would retain part or all of their fish and wildlife populations and habitat. Where existing public access would be restricted in order to reduce hazards to the public, there would be an accompanying reduction of hunting, angling, and camping opportunity on these lands. The importance of these losses would depend upon the capacity of other available habitat areas to absorb the pressures which are presently absorbed by the geothermal area.

Erosion from roads and the construction activities would predictably result in added siltation of aquatic habitat within the area of project influence. This would be most severe during construction phases, although some might extend into the operational stages. Harmful siltation effects would include coverage of fish spawning and feeding areas as well as shoaling of streams. The degree and extent of siltation damage to aquatic habitat within the area of influence would be dependent upon the success of erosion control measures, amount of land disturbance, and type of terrain.

Blowouts - Blowouts, in which steam or water escapes uncontrolled, potentially pose a distinct environmental hazard in geothermal drilling. The principal adverse environmental effects of such accidental releases are safety of operating personnel, waste of the resource, noise nuisance, air contamination from gaseous emissions, and possible pollution of surface and ground water resources. Once a blowout occurs it is troublesome to control because of the difficulty in handling escaping hot fluid. However, unlike similar problems encountered in petroleum drilling, there is essentially no fire hazard in the case of a geothermal accident. To further minimize this hazard, proper casing design is required to assure that the pressurized fluid will be confined to the well bore and can be controlled through surface shut-in equipment.

Ground Water - The ground water regime in the general area of a geothermal field may be irretrievably altered if appropriate control procedures are not employed. A fresh water aquifer may occur above a geothermal reservoir which contains hot saline water. Tapping the geothermal strata could result in contamination of the fresh water if one horizon were not kept isolated from the other by properly cementing the casing of either production or reinjection wells. During the earlier stages of a project suitable data must be accumulated and analyzed, and studies made to determine what steps should be taken to prevent or minimize alteration of the area ground water regime.

Seismic Stimulation - Experience in petroleum production indicates that marked changes in reservoir pressure, whether due to pressure reduction from the production of fluids, or to pressure increase due to injection, may in certain types of reservoirs, especially in faulted or fractured rocks, result in instability leading to earthquakes. Such instability due to production alone has been documented in the Wilmington Oil Field, California (Poland and Davis, 1969, p. 205), instability due to injection was documented at the Baldwin Hills Oil Field, California (Hamilton and Meehan, 1970), at the Rangely Oil Field, Colorado (Healy and others, 1968), and in connection with injection of waste waters at the Rocky Mountain Arsenal, Colorado

(Healy and others, 1970). Similar increases in seismic activity have also been noted in association with filling or large surface reservoirs with attendant change in hydrostatic head, including Lake Mead on the Colorado River and Lake Kariba in Africa (Rothe, 1969, p. 215). The role of fluid-pressure changes in triggering seismic activity is not well known, but a causative relation has been established in many areas. In general, such activity has not proven disastrous, but the potential for a major quake cannot be ruled out. In any event, seismic activity must be counted as a potential environmental impact associated with geothermal development, and provisions must be made for seismic monitoring before and during major production. If monitoring indicates a significant increase in seismic activity particularly in intensity of motion, remedial steps to alleviate stress would have to be initiated promptly.

Subsidence - Subsidence of the ground surface over and around a geothermal reservoir can result from the withdrawal of large volumes of fluids. 1/ Subsidence would reach a maximum rate during full-scale operations unless fluid is returned to the reservoir. In some instances it may be practical to reinject the geothermal fluids after extracting most of their heat. Studies would be initiated prior to approval of operating plans to determine the existence of subsidence

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1/ Poland, J. F. and Davis, G. H., 1969, Land Subsidence Due to Withdrawal of Fluids, Geologic Society of American Reviews in Engineering, Geology II, p. 187-269. Hunt, T. M., Gravity Changes at Wairakei Geothermal Field, New Zealand; Geologic Society of American Bulletin, Vol. 81, p. 529-536.

potential and its probable consequences. If fluids are not reinjected, subsidence measurements should be made during the course of a project, at intervals to be determined by the rate of potential subsidence, to determine whether remedial action would be required.

Noise - Noise due to steam ejection or expansion can be severe and can be expected to reach its highest intensity during testing operations. Such noise can range from a low-frequency to a very high frequency region. Experiments at the Otake Geothermal Power Plants located in the Aso Mountains in Japan have shown that an ordinary expansion chamber muffler is not effective for high-frequency abatement. However, a newly designed muffler used at the Geyser geothermal area effected good noise reduction, even in the high-frequency region, and it did not cause much resistance to steam flow. Venting steam under water also reduces noise effectively.

Power Distribution - Distribution of electric power involves a wide scope of environmental impacts. However, because of the small scale of geothermal developments only the aspects of delivering electricity from the geothermal plant to existing electrical networks are properly assignable to the geothermal development. Normally this would involve construction of lines of 69 kv to 110 kv capacity to provide connection for power generated to the nearest main transmission line. The present practice is to use overhead steel tower lines.

Electrical transmission lines are generally benign and favorable environmental impacts would be limited mainly to improved fire protection resulting from clearing of the rights-of-way and slight improvement in access as well. The principal adverse impacts are aesthetic, due to the intrusion of the structures on vistas. Disturbance of the terrain is minimal except for clearing trees and brush. Transmission lines located in flyways or over nesting and feeding sites would cause some mortality of waterfowl, raptors, and other birds from collision and/or electrocution. The magnitude of this type of loss cannot be predicted but would be expected to be minor with proper design and location of transmission facilities.

Waste Disposal - Solution to problems of waste disposal is vital to successful development of geothermal resources. Geothermal waste fluids normally contain sufficient mineral matter than discharging them into streams and lakes would be generally unacceptable. Even discharge to the ocean might be unacceptable in view of the thermal load. Disposal to otherwise usable underground waters likewise would generally be unacceptable. The solution available in most situations is reinjection of waste fluids into the producing zone. This has the double advantage of providing recharge and pressure maintenance to the geothermal reservoir, as well as providing for waste dispoal. It might be possible to evaporate wastes and recover minerals and salts of economic value.

The favorable impacts of waste disposal through reinjection include pressure maintenance and recharge, which would tend to alleviate potential adverse impacts of land subsidence and increasing seismicity and instability resulting from reservoir pressure decline. Other favorable aspects of not polluting surface waters are self-evident.

With proper management of reinjection works, adverse impacts would be minimal. The potential adverse impact from improper management, however, includes both the pollution of surface and ground waters as well as for increasing seismic activity.

The major potential impact would be upon fish and wildlife which could result from improperly planned or executed handling of geothermal fluids. If controlled releases, spills, seepage or well blowouts were to result in significant additions of toxic or highly saline geothermal waters to streams, ponds, game management areas, etc., adverse impacts would result. These impacts would include the alteration of fishery habitat and waterfowl nesting and feeding areas over the area of influence. If toxic substances, such as boron, sulfides, methane, fluoride, arsenic, and others were present in such releases, they also would exert adverse impacts. Releases of heated effluents to aquatic habitat would alter aquatic habitat and life, perhaps creating temperatures intolerable to existing fish species and stimulating growths of nuisance algae.

Use of excessive pressure in injecting waste waters could conceivably increase seismic activity, but with adequate design and monitoring of reservoir pressure this problem should not be serious.

Another aspect of waste disposal not generally considered is that of gaseous wastes. Steam from cooling towers in some situations could bring on fogging problems, and this should be considered seriously in design and siting of such installations. Likewise release of noxious gases with such steam also constitutes an inverse impact, but certain gases, particularly hydrogen sulfide and ammonia, can be removed from power plant steam before release.

Other Potential Benefits - There are indications that through the combination of desalination processes with energy production, large volumes of usable water could be produced. This could be of particular value in the water-short western state. There also is the potential of mineral production. The investigation of such potentials has only begun so the magnitude and economic feasibility cannot be evaluated at this time. However, it could be that such multi-purpose benefits would result in overall lower system costs that would further enhance the electrical generation potential of geothermal resources.

Summary - Geothermal energy will not be an alternative to traditional energy sources on a nationwide basis but will supplement these sources in areas near geothermal resources where high energy demand exists. Development and production of geothermal resources involve phases of exploration, test drilling, production testing, field development, and power plant and power line construction with full scale operation. Probable environmental impacts would consist of tearing up the landscape for access roads, drilling and construction sites with unsightly equipment and facilities. Construction and drilling debris as well as erosion will injure local water supplies. Occasional venting breaks with accompanying noise and atmospheric pollution will occur. Possible environmental impacts involve blowouts with subsequent noise and contamination, detrimental effects to fish and wildlife populations, ground water contamination of fresh water aquifers, triggering seismic activity, including subsidence, contaminating the surface and atmosphere with hot toxic waters, and fog created from cooling geothermal waters. Beneficial impacts as a result of fresh water, improved acess to lands, and mineral production are also a possibility.

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2. Tar Sands

a) Description of Alternative

Reservoirs of hydrocarbons that are too viscous to be recovered in their natural state and by conventional oil production methods are called tar sands or bituminuous sands. Typically reservoir energy is nonexistant and for production to be significant other energy must be added in some manner, either by direct heating, fluid pressure, or mechanical work.

Of the many known North American tar sand deposists, only a few are likely to be of major commercial interest in the next 15 to 30 years. Chief among these are the Athabasca deposits in northern Alberta, Canada, and the Orinoco deposits in eastern Venezuela. 1/ Only five deposits in the United States of 0.5 billion barrels or more are worth considering in relation to affecting United States energy supply. All of these deposits are in Utah and are estimated to contain about 17.7-27.6 billion barrels of tar and resources in place, based on relatively few drill holes supported by outcrop data. Recovery would only be on the order of 30-50% of the in-place reserves, reducing these reserves to 10-16 billion barrels of recoverable oil. Another estimate of U.S. tar sand reserves, based on shallow occurrences only, range from 2.5-5.5 billion barrels of recoverable oil. 2/

1/ U. S. Energy Outlook, National Petroleum Council, November 1971.

2/ U. S. Bureau of Mines Monograph 12, 1965.

Production from Domestic Tar Sands - Three states have occurrences of tar sands; Utah, California, and Kentucky. Presently only in Utah is there any production potential, furthermore, the Utah deposits are not susceptable to mining, but more likely will be developed by in situ methods, the technology for which has yet to be developed. In either method, a major shortcoming is a lack of an adequate water supply in proximity to the deposits.

In addition to technological problems other legal and developmental problems exist. The Tar Sand Triangle and Circle Cliffs giant deposits are largely on Federal lands. Leasing of Federal lands for "asphaltic minerals" or tar sands has been delayed pending legislation.

Proposals for national parks, national monuments, desert wilderness areas and recreational areas cover most of the Circle Cliffs and Tar Sand Triangle giant deposits and could result in surface uses incompatible with mineral resource development. In the P.R. Spring giant deposit, the tar sands and shale oil deposits are superimposed, creating potential legal problems with long costly delays. Finally, lead time for mining ventures range from 4-7 years, for inception to full production, and can become an important consideration to production possibilities.

Canadian Production - The largest most accessible tar sand deposits occur in the Athabasca region of Canada. The NPC [1] estimates that 174 billion barrels may be economically recoverable. Others estimate as little as 85 billion barrels are minable. Canadian production is currently limited by licensing requirements in addition to technical problems but Canadian production by 1985 of 500,000 to 1,000,000 barrels per day is anticipated. Increasing sensitivity of Canadians to the environment and lack of a local Canadian market for the oil could cause considerable delay. 1/

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[1] U. S. Energy Outlook, National Petroleum Council, Vol. II, 1971.

Recovery Methods - National Petroleum Council 2/ study reached the following conclusion regarding production of tar sands by strip mining methods:

a. Mining Extraction

"The mining extraction route is most applicable to the shallow deposits (up to 100 or 150 feet of overburden). Because about 12% by weight, an immense tonnage of sand and overburden must be moved, using strip mining methods, to support an economically large synthetic crude output. On a unit basis, the ratio is about 2.4 tons of sand and 1.0 ton of overburden, more or less, per barrel of synthetic crude. Local variations in overburden ratio and/or tar sands quality over a given lease area can result in condemnation, on economic grounds, but always respecting good conservation practice, of significant portions of a lease. Thus, an overall average utilization of total tar sands in a mining leasehold might be on the order of 75%."

1/ Oil Week, January 29, 1973.

2/ Op. cit., 1971.

b. In Situ Recovery

"The two methods most thoroughly researched and tested in the field involve (1) injecting steam plus an emulsifying agent (e.g., caustic soda as used in a Shell Oil Co. trial) into the deposit and (2) using thermal-recovery or "fire-flooding" techniques, as experimented with Amoco (Canada) and others. For either method to succeed, communication must be established downhole in the formation between the injection wells and the production wells. Field tests have determined that this can be achieved. Overall recovery of in-place bitumen via either in situ technique is estimated to be on the order of 35 to 50%, distinctly lower than the corresponding value for mining extraction."

The mining extraction route has the option of being the more economical method per unit of area exploited but causes large scale surface disturbance in both the mining and the storing of mined material to be processed. In situ processing, although lower recovery per unit of area exploited, would leave no sand tailings disposal problem. Few large areas in the U.S. would be susceptible to strip mining methods because of depth of overburden. Plans and techniques for underground mining are unknown at this time. The in situ method presently holds the greatest promise for recovery of the U.S. deposits.

Processing - Athabasca bitumen is a naphthene base, black material containing relatively large amounts of sulfur, nitrogen, and metals. With a specific gravity of 6 to 10 API and a viscosity roughly in the range of 35,000 Saybolt Universal Seconds at 100° F., the material is unsatisfactory for feed to conventional oil refineries and impossible to ship via pipeline to distant refining centers. This necessitates some from of pre-refining in the field. To accomplish this "upgrading" of the bitumen some means of hydrogen-enrichment is needed and some fuel must be set aside for the pre-refining as well as for production of hydrogen.

In the process of hydrogen-enrichment, the sulfur and nitrogen contents are reduced to tolerable levels and the metals exist with the carbon residue leaving an acceptable to superior synthetic crude oil for shipment to ordinary refineries. The carbon residue is then recycled as a fuel for the pre-refining operation. Existing technology can provide the devices necessary to control particulate matter, sulfur dioxide, and nitrogen released into the atmosphere during this processing.

Many methods have been proposed for recovering oil from mined tar sands. Great Canadian Oil Sands LTD via coking and hydrogenation of coker distillates get a synthetic crude product/bitumen volume ratio of 0.78. Syncrude Canada Ltd., with hydrovis breaking plus hydrogenation of distillates gets a ratio of 0.87. The loss in product is accountable for by the material set aside for fuel and for production of hydrogen in the upgrading process.

b) Environmental Impact

Tar sand development would effect the environmental in all phases of development; exploration, mining, production, and transmission of the synthetic crude.

Exploration - Standard exploration techniques are likely to have an affect on the environment. Seismic disturbance associated with initial geophysical surveys delineating the extent of the prospective producing zone would temporarily disturb some domestic animals and wildlife in the area. Other sophisticated methods as gravity, and electromagnetics which are used to determine regional geological structure in the area would not likely disturb animal life. Exploration drilling would involve access roads, drilling sites, mud ponds, and unattractive storage areas. Soil erosion associated with this activity could effect local surface waters and the fish in them. Drilling operations could contaminate various subsurface aquifers by using certain drilling mud additives or intermixing saline and fresh water aquifers. Debris and wastes associated with any construction and drilling activity could have an impact on aesthetics, especially important in tar sand areas due to interest in land use for wilderness areas, recreational areas, national parks, etc.

Mining - Once exploration has determined an area to be profitable, a choice of using mining-extraction or in situ will have to be made. The mining-extraction method has the advantage of greater recovery, but the environmental disadvantages of: a) large unsightly amounts of tailings and overburden distributed over the ground surface, b) excavations in both open pit or underground mining which disrupt the surface, c) dust and erosion problems which are often associated with tailings, d) possible contamination or depletion of a local aquifer in a water poor area, e) disruption in wildlife habitat by using tailings areas, mine areas, and associated mining activity. Although in situ methods will not face the tailings problems, disadvantages are also present: a) thermal pollution involved with large amounts of heat put into the ground, b) possible contamination of aquifers, c) surface spills due to machinery failures, d) or possible surface subsidence with accompanying land disturbance; e) noise could be a problem depending on the equipment being used.

Processing - A well designed pre-refining system of processing tar sands should meet current Federal air standards. The sulfur and nitrogen removed from the bitumen could become a source of air pollution with faulty plant design. Metals removed from the bitumen and associated with the carbon residue unless adequately disposed of, could be a local pollutant. Noise, lighting, and activity associated with a plant could have a detrimental affect on wildlife and aesthetics. Development of the area to house workers and family will cause associated drains on local water supplies and destroy the natural appearance of the area.

Transporting Syncrude - In this final stage, all the impacts of the other stages will have their cumulative effect. Should any petroleum transporting pipelines be ruptured in the dry remote areas as those particularly associated with tar sand resources, considerable time would be necessary to restore the environment. Road transportation by trucks could cause oil spills and dust problems. Rail or pipeline transportation of the syncrude would also be subject to spills through ruptures, caused by natural catastrophies or human error.

Summary - Most tar sands of commercial interest in the United States are located in Utah. Although considerable production from large Canadian deposits can be expected before 1985, Utah deposits have a number of obstacles blocking their development. These deposits are located on lands that have considerable recreational appeal and proposals have been made to make the land into wilderness areas, national parks, or other recreational areas. A second problem of favorable legislation in leasing "Asphalt Minerals" exists. High capital cost, and lack of a good local water supply also hinder development, although the syncrude produced compares favorably with natural crude.

Environmental problems appear in the exploration, mining, processing, and transportation of syncrude. The extent of local disturbance is partially determined by whether mining-extraction or in situ techniques are used. Wildlife and aesthetics would not escape a detrimental effect.

3. Hydrogen

a) Description of the Alternative

The basic technology of using hydrogen as an alternative to fossil fuels exists and although energy intensive, it leaves the greatest obstacles to this relatively pollution free source of energy a matter of economics and timing. By passing a strong electric current through water in a process called electrolysis, water can be separated into its main gaseous components oxygen and hydrogen. The hydrogen can be piped as a gas or subsequently liquified and shipped to be used as a fuel.

Prior to 1958, liquid hydrogen was produced only in small quantities and was primarily a laboratory curiosity. The 1972 hydrogen production was more than 12 billion pounds in the U.S. alone, and is used primarily in making refined petroleum products and chemical synthesis. Only a small fraction of this total production comes from the electrolysis of water, the great preponderance being produced by much cheaper methods of breaking down natural gas, oil and to a lesser extent coal through various catalytic streams and partial combustion processes.

Future speculations for massive hydrogen producing facilities include great floating platforms some miles offshore in the oceans. These platforms would house a series of big nuclear power plants which would generate power for spot decomposition of sea water by electrolysis, the hydrogen produced could be piped ashore. The potential advantages of such a system are numerous. Hydrogen gas could be piped to its point of use at about one-eighth the cost of sending an equivalent amount of electricity through high-voltage overhead cables. Underground pipe transmission of gaseous hydrogen would eliminate unsightly overhead wires. Unlike electrical capacity which is difficult or inefficient to store, hydrogen could be stored as gas in underground cavities or as a compressed liquid in large insulated tanks to meet fluctuating power demands. Already under development are fuel cells which convert hydrogen and oxygen directly into electricity. Advanced electrolitic cells have also begun development which work by feeding in current to catalytically separate oxygen and hydrogen at a 1/4-1/3 reduction in power required.

The major advances made in hydrogen technology in the last decade are largely a spin-off of rocket and space programs. Liquid hydrogen engines have powered nine astronaut crews safely to the moon and back. In the future these engines are scheduled to play an even larger role in the space shuttle.

The economics and timing of hydrogen's first use as a fuel are complex matters. Presently liquid hydrogen is only about 50% more expensive than gasoline on a btu per unit weight basis since liquid hydrogen is so much higher in energy content. Actual cost projections for the electrolytic production of hydrogen range from a low of $0.04 per pound using electrical energy from a larger breeder type reactor to about $0.12 per pound for other energy sources. Presently gasoline costs of production are about $0.02 per pound. Hydrogen gas is so light it cannot match natural gas in heat value or a volumetric unit basis. The first hydrogen gas should enter the economy in hybrid gas mixtures that stretch natural gas supplies or may be mixed with synthetic gas products from coal perhaps before 1980. It is possible to convert present gas lines to handle hydrogen though at considerable changeover costs. Transmitting costs of the lighter gas would double or triple, as well as the need for tighter more carefully maintained piping systems, even though the lighter gas could move more rapidly.

With some mechanical modifications all types of internal combustion engines can burn hydrogen cleanly. In the summer of 1972, at the Urban Vehicle Design Competition of 63 experimental cars, the two least polluting were cars converted to run on hydrogen, one of which was the only car to exceed the 1975-76 Federal emission standards. Buses, trucks, ships, locomotives can all run on hydrogen with their present engines although somewhat less efficiently. It can also be burned in the home for heating or cooling. In any combustion of hydrogen as a fuel the only major waste product is water. Additional uses, as the direct reduction of iron ore, dispense with coal and coke use as is already being done at several steam power plants.

With all the exciting possibility, conversion costs remain extremely high, particularly to the consumer. Enormous investments of capital will be necessary as well as demonstration projects to work out technical problems. It is possible that the use of hydrogen as a fuel could be substantial by the mid-1980's. Large amounts of energy needed for electrolysis could presently be provided only by fossil fuel which would not relieve energy supply or environmental problems.

Projections of this alternative remain highly speculative due to its largely experimental nature and its early stage of development.

4. Biological Energy

Biological energy has attractive prospects in two major areas. One is the production of alcohol from crops, particularly unused crop surpluses, and the other involves the conversion of organic wastes into usable oil.

The efficiency of U.S. agriculture has advanced so fast that for several decades crop production has exceeded demand except in times of international conflicts and in early 1973 when heavy international buying coupled with unusually bad weather drained surplus stores. Average farm production has increased about 80% in the last three decades, largely owing to better yielding seeds and greatly improved "know-how". Thus, to meet our crops needs, we plant fewer acres and require fewer farmers. 1/

Agriculture provides the major current source of renewable energy. Forests, cultivated crops and pasture land may be used repeatedly under proper management. Agriculture production is, however, subject to weather, diseases, wind, and other natural conditions which cannot yet be completely controlled. Nevertheless average production in excess of priority requirements for domestic food, feed and fibers is believed by 1985, and beyond, barring natural disasters or national emergencies. The production of cereal grains and their conversion through fermenta-

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1/ New Energy Forms Task Group, 1971-1985, Other Energy Resource Subcommittee of National Petroleum Council Committee on U.S. Energy Outlook, 1972.

tion to usable ethly alcohol fuel; the collection and use of such residues as straws, corncobs, hulls and shells for fuels; the growing of crops for fuel energy; and the conversion of animal by-products into fuels are all possibilities.

Agricultural fuels would normally be more expensive than such traditional fuels as coal, gas, oil and waterpower. Increasing U.S. needs for energy, requirements for pollution abatement and many other economic factors could, however, materially change the future role of agriculture as a source of industrial energy.

Of the approximately 2,260 million acres of U.S. land available, about 25% is classified as forest and woodland and about the same proportion is land suitable for cultivation. Most of our woodland will probably be required to meet the predicted demands for lumber, pulp and paper industries, and thus will offer only minor possibilities for contributing to additional U.S. industrial energy supplies. On an average, however, only about 60% of the potentially available cultivated land is now farmed for crops. Yields of cereal grains on these lands have, on an average, increased about 3% annually for the past decade. This increase has exceeded the U.S. population growth, even though the amount of cultivated land has decreased. Thus, unused acres constitute a potential source of energy for the foreseeable future.

A logical sequence of energy conversions is to use this land to produce cereal grains, which are large carbohydrate, and then to convert these grains by fermentation into ethyl alcohol, which is a convenient combustible fuel readily usable in motors. If we assume that the 100 million acres, or about one-half of the acres not now required, are used to produce the grain for alcohol at a yield of 70 bushels per acre, this would be equivalent to about 18 billion gallons of motor fuel consumed in the U.S. in 1970. Since ethyl alcohol contains only 65% of the energy content of gasoline, on a gallon basis, the actual energy replacement would be only 14%.

The cost of this ethyl alcohol from fermentation would be many times higher than the cost of present motor fuel. Even so, this tremendous energy potential must be considered in any assessment of future energy sources.

The quantity of organic waste generated in the United States annually is enormous and will continue to increase. Below are summarized various amounts of wastes produced and amounts available as well as potential for conversion into oil and gas. 1/

According to the study below, 1971 collectable agricultural residues in the U.S. amounted to over 130 million tons annually with an oil potential of 170 million barrels, roughly equivalent to 47 million tons of low sulfur coal. To produce the oil from waste, the organic material is treated with carbon and water at 250°-400° C. and 2000-

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1/ Data from Bureau of Mines.

5000psi pressure. This oil product has a heating value of 15,000 btu per pound and the total energy potential would be on the order of 2000 trillion btu. High collection and processing costs, incomplete technology, along with high capital requirements, prevent this energy source from being economically competitive. Presently only one continuous unit with a capacity of 20 pounds per hour is being operated on a test basis. Although the total potential energy from organic waste is enormous and growing, economic considerations will likely prevent this source from having a significant effect on the U.S. energy picture by 1985.

Estimates of Organic Wastes Generated, 1971 and 1980			1971 Organic Solids Available for Conversion
	1971	1980	
Source:			
Manure....................mil. tons/year...	200	266	26.0
Urban refuse..................do.........	129	222	71.0
Logging and wood manuf. residues..do.........	55	59	5.0
Agriculture crops and food wastes 1/..do...	390	390	22.6
Industrial wastes.............do.........	44	50	5.2
Municipal sewage solids........do.........	12	14	1.5
Miscellaneous organic wastes...do.........	50	60	5.0
Total.........................do.........	880	1,061	136.3
New oil potential...million barrels........	1,098	1,330	170
Net gas for fuel potential...tril. cu. ft..	8.8	10.6	1.36

Environmental Considerations - To use crops to create alcohol is not likely to raise any more pollution, in fact, proper farming techniques would probably reduce soil erosion and increase productivity of the land.

1/ Assuming 10% dry organic solids in major agricultural crop waste solids.

To use animals waste for conversion to fuel would have the obvious advantages of disposing of a pollutant itself and recycling it into a useful product. Areas of high population density, produce greater wastes and would have a locally available source of fuel in proportion to their population. Water quality problems associated with organic wastes could be alleviated. The residue would be sterile although large amounts of bulk material would still have to be placed somewhere, perhaps as land fill.

The oil produced has properties varying with the type of material composing the waste. Shown below are the sulfur contents of oils produced from various sludges. 1/ All of them meet the Federal fuel standards of 0.7% sulfur. A distinct advantage in waste conversion would be to reduce demand on natural resources commensurate with the amount of oil and gas made from these wastes.

	Percent Sulfur
Pineneedles and twigs..............	0.10
Sewage sludge.......................	.64
Municipal refuse....................	.13
Cow manure..........................	.37
Cellulose...........................	.003-.2

1/ Bureau of Mines data, 1971.

5. Solar Energy

Solar energy is a source of both heat and electromagnetic radiation and possibilities exist for both direct and indirect use of this energy. Fossils fuels are representative of solar energy stored from earlier periods in the earth's history, which, when ignited, release the energy plants and animals accumulated eons ago. An indirect way of using solar energy in more recent history would be burning fuel, wood or plants directly, while direct use would be a solid state solar cell.

Four characteristics of solar energy deserve particular notation.

(a) it is a diffuse, low intensity source of energy;

(b) the energy is spread over various frequencies (i.e., distributed over the various wave legths of light);

(c) its intensity is continuously variable during the daylight hours, is zero at night, and is subject to weather and seasonal variations; and

(d) its availability differs widely between geographic areas.

A consequence of the diffuse nature of solar energy is that it does not naturally produce the high temperature characteristic of combustion processes. This is a definite disadvantage since high temperatures make possible greater thermodynamic efficiency in energy conversion.

The U. S. land area intercepts each year about 600 times its total 1976 energy requirements at an intensity of radiation of 1 KW M^2 or less.[1] At a 10% efficiency each square meter of active surface will produce not more than 100 watts of peak power.

Such heat can be used for electricity generation, space heating, cooling, and processing of industrial materials. The Solar Energy Laboratory of the University of Florida at Gainesville conducts extensive research in solar energy utilization. Among the applications under development are solar water heating, swimming pool heating, home heating, solar baking, solar distillation, solar power plants, solar cooking, solar furnaces, solar pumps and turbines, and solar sewage treatment. The following tables show the state of development and technical problems of solar energy applications.

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[1] IT&T Consultative Committee, 1970 Primary Sources of Energy.

Present Status of Solar Utilization Techniques

Application	Status					
	Research	Development	Systems test	Pilot plant demonstration	Prototype plant	Commercial readiness
Thermal energy for buildings						
Water heating	X	X	X	X	X	X
Building heating	X	X	X			
Building cooling	X	X				
Combined system	X	X				
Renewable clean fuel sources						
Combustion of organic matter	X	X	X	X		
Bioconversion of organic materials to methane	X	X	X	X		
Pyrolysis of organic materials to gas, liquid, and solid fuels	X	X	X	X	X	
Chemical reduction of organic materials to oil	X	X	X			
Electric power generation						
Thermal conversion	X					
Photovoltaic						
Residential/commercial	X					
Ground central station	X					
Space central station	X					
Wind energy conversion	X	X	X			
Ocean thermal difference	X	X	X			

X indicates effort is underway but not necessarily complete.

Source:
Solar Energy as a National Energy Resource, NSF/NASA
Solar Energy Panel, Dec. 1972, p. 8.

Summary of Major Technical Problems

Application	Major technical problems to be solved
Thermal energy for buildings	Development of solar air-conditioning and integration of heating and cooling.
Renewable clean fuel sources	
Combustion of organic materials	Development of efficient growth, harvesting, chipping, drying and transportation systems.
Bioconversion of organic materials to methane	Development of efficient conversion processes and economical sources of organic materials.
Pyrolysis of organic materials to gas, liquid and solid fuels	Optimization of fuel production for different feed materials.
Chemical reduction of organic materials to oil	Optimization of organic feed system and oil separation process.
Electric power generation	
Thermal conversion	Development of collector, heat transfer and storage subsystems.
Photovoltaic	Development of low-cost long-life solar arrays.
Systems on buildings	High temperature operation and energy storage.
Ground station	Energy storage.
Space station	Development of light-weight, long-life, low-cost solar array; transportation, construction, operation and maintenance; development and deployment of extremely large and light-weight structures.
Wind energy conversion	Integration of large wind conversion system with suitable energy storage and delivery systems.
Ocean thermal difference	Large low pressure turbines, large heat exchangers, and long, deep-water intake pipe.

Source:
Solar Energy As A National Energy Resource, NSF/NASA
Solar Energy Panel, Dec., 1972, p. 9.

Properties of solar radiation produce photosynthetic conversion which also converts and stores energy.

About half the energyin the solar spectrum lies in wavelengths usable in photosynthesis. The efficency of this half can be in the neighborhood of 50 percent, giving an overall possible photosynthetic conversion of 25 percent. In experiments, efficiencies in the usable spectrum ranged from chlorella (a green algae) at 20 percent conversion efficiencies to about 2 percent for sugar cane. Experiments in Japan to use chlorella have always fallen short of economical use as food. Consequently using it for fuel with a lower unit value than food would also be uneconomical. Since chlorella rates high in efficient conversion of solar energy, other plants don't appear to hold good prospects for useful conversion of solar energy.

Non-biological solar processes are based on either of two fundamental concepts: flat-plate collectors or focusing collectors. Flat-plate collectors consist of flat, blackened surfaces to absorb solar radiation. On the plate, solar radiation is converted to another form of energy, usually heat, which is removed from the plate usually in the form of heated water or air. Flat-plate collectors generally operate in a fixed position.

The focusing collector consists of an optical device (a parabolic collector) to focus the beam component of solar radiation on a receiver smaller than the reflector. The focusing collector allows energy collection at higher temperatures than the flat-plate collector. The intensity of radiation on the receiver may range from 2 to 3 times to 10,000 to 20,000 times that of the incident beam solar energy on the optical system. At all but the lowest ratios, some degree of "sun tracking" is needed as the direction of the incoming beam radiation changes.

With very few exceptions, all practical solar energy systems now in use are flat-plate collector systems. Materials, costs, and operational difficulties have prevented widespread application of focusing collector systems.

The silicon cell, developed about 15 years ago, has proved to be a reliable means for this direct conversion of solar radiation to electricity for applications in outer space. The generation of significant amounts of power, however, requires the connection of extremely large numbers of cells. The capital cost of silicon cell arrays results in power costs on the order of $2.00 to $5.00 per KWH. Thus, the cost is about 1,000 times that of conventional power sources.

Another potential application of solar energy is use of thermal gradients to extract the solar energy stored in the surface layers of the ocean. The summer sun melts down the polar ice, which slides to the depths of the ocean and moves toward the equator. Above the cold deep water, the surface layers in the tropics remain at a temperature above 80 F. This difference in temperature can be used to generate electricity.

Several proposals have been made to apply this concept to the warm waters of the Gulf stream, which approaches close to the southeastern coast of Florida. The temperature difference between surface and deep water ranges from 27°F to 39°F. The theoretical efficiency of conversion of heat into useful work of about 5 percent is possible at the surface temperature of 72°F.

One scheme to exploit thermal gradients envisages a submerged floating platform. The surface water is used to boil propane at high pressure. The propane gas then powers a turbine to generate electricity. The propane is cooled by the deep ocean water and returned to the boiler. Floating power plants could be located either well out in the moving water of the Gulf stream or near shore in nearly stagnant water. Preliminary estimates of the capital cost of such plants is from $200 to $400 per KW of capacity. These plants could also be used to produce fresh water, and through electrolysis, hydrogen and oxygen. Another possibility is cultivation of shellfish in the nutrient rich cold water brought up from the deep ocean. Multiple uses of thermal gradient plants would make the economics more favorable.

At the University of Massachusetts, Amherst, William Heronemus and his colleagues are preparing preliminary designs for a submerged power plant in the Gulf Stream. One proposed site is the western edge of the Gulf Stream about sixteen miles from Miami. The concept being considered now is a modular design with six turbines in each of two hulls, hooked together. Towers to the surface would provide ventilation and access to the plant. The station would generate about 400 MW of electricity.

Ocean thermal gradient systems appear to offer the possibility of becoming cost competitive with other sources. Much work remains to be done on design of the plants, environmental effects, transmission of electricity to shore, and selection of the working fluid (the fluid which is vaporized by the hot water and then expands through the turbines and is condensed for reuse).

Among the potential applications of solar energy, residential heating and cooling has the highest chance of success. Solar water heating has long been used in southern Florida, although less extensively than in the past because of the availability and low cost of natural gas. The main elements in solar water heating are a flat-plate collector and an insulated storage tank. Water circulates through the collector, is heated, and is held in the tank for use when needed. Solar water heaters are commercially manufactured in Australia, Israel, Japan, the U.S.S.R., and, on a small scale, in the U. S. The technology of solar water heating is well developed. Product engineering and large scale manufacturing may reduce costs and increase use.

Solar space heating is not yet as advanced as solar water heating. In the past decade, about 25 houses have been built in the U. S. with heating systems powered largely by solar energy. The University of Delaware has completed an experimental house, called Solar One, that will use solar heating and cooling and will convert sunlight into electricity to run home appliances.

Extensive application for solar power exists in home heating using relatively inexpensive collectors costing \$2.00 - \$4.00 per square foot and using auxillary heating when necessary. A 1967 study of this example is used below. 1/

Table VIII-3

SOLAR HEATING COST COMPARISON

	Cost of heat (\$/10^6 Btu)		
Climate classification		Electricity	Gas-Oil (average) ← Fuel cost only 75% combustion efficiencies
Santa Maria: Mediterranean or dry summer, sub-tropical	1.10-1.59	4.36	1.52
Albuquerque: Tropical and sub-tropical steppe	1.60-2.32	4.62	1.48
Phoenix: Tropical and sub-tropical desert	2.05-3.09	4.25	1.20
Omaha: Humid continental, warm summer	2.45-2.98	3.24	1.18
Boston: Humid continental, cool summer	2.50-3.02	5.25	1.75

1/ The International Telephone and Telegraph Consultative Committee, 1970 Primary Sources of Energy.

Climate Classification	Solar Heat	Electricity	Gas-Oil (average)	Fuel cost only 75% comb. efficiencies
Charleston: Humid sub-tropical	2.55-3.56	4.22	1.26	
Seattle/Tacoma: Marine West Coast	2.60-3.32	2. 1	1.92	
Miami: Tropical savannah	4.05-4.64	4.90	2.27	

A long-range objective is large-scale production of electricity using either arrays of large collectors or even satellites equipped with solar cells that would surmount the problem of cloudy days. These schemes are not likely to be practical for one or two decades.

The sun provides a pollution-free, non-depleting source of energy. Few applications of solar energy are cost-competitive with other energy sources at the present time. However, solar energy will become more attractive as technology advances and the costs, environmental and otherwise, of the other energy sources rise. Residential heating and cooling has the highest potential for short-term application.

The following table compares estimated costs of electricity generated by fossil fuels and solar power. The data illustrate the high capital costs of solar power.

Electrical generation costs comparisons (estimated)

	Type of Powerplant				Satellite solar powerstation			Terrestrial
	Coal-fired	Oil-fired	Gas-fired	Nuclear	Low	Med.	High	Solar powerstation
Unit investment cost of plant, $/kw	200	140	130	300	1,400	2,100	2,600	1,100
Annual fixed charges, percent of investment	17	17	17	17		17		17
Kilowatt-hours generated per year per kilowatt capacity	7,000	7,000	7,000	7,000		8,760		4,000*
Efficiency, percent	34	34	34	33		11		30
Cost of fuel, ¢/10^6 Btu	36.2	55.2	29.4	17.5		0		0
Cost of electricity, mills/kwh:								
Plant investment	4.8	3.4	3.2	7.3	27.2	40.7	50.5	46.7**
Operation & maintenance	1.0	0.6	0.5	0.4		Undetermined		Undetermined
Fuel	3.6	5.5	3.0	1.7		0		0
Total	9.4	9.5	6.7	9.4		---		---

* Maximum; assumes no facilities for storing electricity for use at night or on cloudy days.
** Less if facilities for storing electricity are available.

Source: Compiled by Division of Fossil Fuels, U. S. Bureau of Mines.

The Department of the Interior, Bureau of Land Management, is using solar power in mountain top radio communications sites. The first units were installed about ten years ago. Today, there are about fifteen units in Alaska and about forty in remote areas of other states. The Bureau plans to install or convert many more such units in the next few years. The silicon solar panels cost $100 per watt a few years ago and now cost $50 per watt. Panels with a large variety of wattages are available. Developing technology and increasing competition among producers may lower costs to about $10 per watt in the next five years. Installations of this type can be made with minimal environmental impact since access roads are not required and inspection and maintenance are infrequent. The units are being used instead of propane powered thermo-electric generators since propane is in short supply and must often be flown in to the sites by helicopter. Propane delivery to some sites requires a four hour trip at a cost of about $500 an hour for the helicopter. The solar panels are used to charge batteries that supply power to radios. The units can be preassembled, flown in by helicopter, and installed in a few hours.

The federal government has set aside funds for solar energy research within the RANN program (Research Applied to National Needs Program). The purpose of this program is to focus scientific research on problems of national importance, and contribute to their practical solution. The program is implemented primarily through universities.

Fiscal year 1972 funding for solar energy was $1.7 million, FY73 funding was $4.2 million, and FY74 funding was $12.2 million. The objectives of the solar energy activity are to emphasize research in the following three areas of solar applications:

Economical systems for heating and cooling of buildings;

Economical systems for producing and converting organic materials to liquid, solid, and gaseous fuels; and

Economical systems for generating electricity.

Expected accomplishments stemming from this research include an evaluation of the technical, economic, environmental, and social factors related to practical solar energy systems in seven areas:

Solar thermal energy for buildings;

Photosynthetic production of organic materials and hydrogen;

Conversion of organic materials to fuels or to energy;

Solar thermal conversion for electric power generation;

Photovoltaic conversion for electric power generation;

Power from atmospheric circulation; and

Power from ocean temperature differences.

6. Tidal Power

Tidal power is a hydroelectric energy source similar to other water power sources except it is derived from the alternate filling and emptying of a bay or estuary that can be enclosed by a dam. The total tidal power dissipated by the earth is enormous, largely accounted for by oceanic tidal friction in bays and estuaries around the world although theoretically it could be captured and converted to electric power. Despite this total potential, practical considerations have eliminated all geographic areas except where tidal behavior, range, and water displacement are extremely favorable.

Two plants are presently operating, the larger is the Rance Plant on the Rance River estuary Brittany, France which was completed in 1967 at a cost of $90 million, a capacity of 240 MW, to be increased to 320 MW. The present cost is about $350/KW. The U.S.S.R. completed its first plant on the White Sea in 1969 which has a 1000 KW capacity. Other proposals include the Bristol Channel, U.K., San Jose Gulf, Argentina, and the western Australian Coast. The Canadian government studied 23 sites on the Bay of Fundy, with its potential included below (New Energy Task Group, 1972):

POTENTIAL TIDAL ENERGY

	Bil. KWH/Yr.
Passamaquoddy Bay, U.S./Canada	1.8
Cook Inlet, U.S.	75
Bay of Fundy, Canada	
3 Sites, single effect	13.4
3 Sites, double effect (incoming, outgoing tides)	16.8
Total Potential, of the entire Bay of Fundy	175

Even with the potential of the Bay of Fundy's 35 foot tides, the project was abandoned in 1969 by the Canadian Government as uneconomical.

The only practical opportunities for economic development in the United States appear to be in the vicinity of Passamaquoddy Bay, Maine and perhaps Turnagain Bay in Cook Inlet, Alaska. The higher potentials for Cook Inlet is negated by economics and distance from the market. Passamaquoddy Bay has a tidal range of 18 feet. Capital costs of as high as $1 billion for the 1.8 billion KWH/yr. were calculated in a detailed 1964 Senate Subcommittee proposal for development. With enormous increases in demand, the significance of this contribution has lessened and the project has been determined to be uneconomical.

Some possibility exists that with better interest rates and a decline in alternate energy sources the Canadian Government will develop a portion of the Bay of Fundy before 1985. Some of this power could become available to the New England region of the United States. Assuming a maximum of 10 billion KWH from this source could be available by 1985, this would still be only 2% of the projected electrical energy required by the New England region at that time. The attraction of the renewable nature of tidal energy is a great advantage although the total amount of energy is relatively low.

Environmental problems would be considerable. Although no air pollution would exist, damming with alternate filling and emptying of bay and estuary areas would effect shipping, drainage, sport and commercial fisheries, wildlife, water quality, aesthetics, recreation, accumulation of sands and silts, as well as numerous other uses of present bays and estuaries.

7. Wind Energy

Description of the Alternative

Energy can be obtained from the wind by means of a device which will extract energy from a moving mass of air. A fixed device can capture kinetic energy by rotation about an axis and, coupled to a generator, convert it into electricity. Economical power generation requires an average annual wind velocity of about 30 mph, a nearly constant magnitude, and topography in which boundary - layer effects are minimal.

The advantages in using wind energy are the following: a) the supply is inexhaustible; b) it is available in many parts of the world; c) the energy is free on the site of production. Some of the practical disadvantages are: a) the low energy density of the wind; b) the wind velocity is unpredictable in time and magnitude, c) the low conversion efficiencies of aeromotors; d) the effect of icing conditions and weather on aeromotors, and e) the high cost of money required for the capital investment.

In Demark between 1940-1945 when fuel oil was in short supply, 88 wind-driven installations generated 18,000 mwh for local needs. Below are listed examples of large wind-driven generator installations.

Table VIII-4
Large wind-driven generator installations 1/

Country	Location	Date	Capacity KW
U.S.S.R.	Balaclava	1931	100
U.S.A.	Vermont	1941	1250
Denmark	Gedser	1959	200
United Kingdom	Orkney	1952	100
United Kingdom	St. Albans	1954	100

By combining wind-driven generators with diesel standby units, continuous, small-scale, dependable power can be locally generated. This method has supplied lighthouses for over ten years at several locations, but at a capacity of less than 10KW. Presently there is only one major research project to harness the wind's energy at the University of Hawaii with a budget of just over $100,000/yr.

The following table shows the maximun electrical energy production from wind power for different regions of the U. S. as estimated by the NSF/NASA Solar Energy Panel. The panel suggests that, assuming intensive research and development effort and sucessful development of practical, economically competitive systems, this maximum could be achieved by the year 2000 and would provide about 19% of annual electricity production in that year.

At the present time, wind energy is not cost competitive because of

Maximum Electrical Energy Production From Wind Power

Site	Annual power production
(1) Offshore, New England	159 × 10^9 kWh
(2) Offshore, New England	318 × 10^9 kWh
(3) Offshore, Eastern Seaboard, along the 100 meter contour, Ambrose shipping channel south to Charleston, S.C.	283 × 10^9 kWh
(4) Along the E-W Axis, Lake Superior (320 m)	35 × 10^9 kWh
(5) Along the N-S Axis, Lake Michigan (220 m)	29 × 10^9 kWh
(6) Along the N-S Axis, Lake Huron (160 m)	23 × 10^9 kWh
(7) Along the W-E Axis, Lake Erie (200 m)	23 × 10^9 kWh
(8) Along the W-E Axis, Lake Ontario (160 m)	23 × 10^9 kWh
(9) Through the Great Plains from Dallas, Texas, North in a path 300 miles wide W-E, and 1300 miles long, S to N. Wind Stations to be clustered in groups of 165, at least 60 miles between groups (sparse coverage)	210 × 10^9 kWh
(10) Offshore the Texas Gulf Coast, along a length of 400 miles from the Mexican border, eastward, along the 100 meter contour	190 × 10^9 kWh
(11) Along the Aleutian Chain, 1260 miles, on transects each 35 miles long, spaced at 60-mile intervals, between 100 meter contours. Hydrogen is to be liquefied and transported to California by tanker.	402 × 10^9 kWh

Estimated Total Production Possible: 1.536 × 10^{12} kWh

Source. Solar Energy As a National Energy Resource, NSF/NASA Solar Energy Panel, Dec. 1972, p. 69.

high equipment, energy storage, and back up equipment costs coupled with the intermittent characteristics of the wind. Research and development is needed in fuel cells, and concepts using wind generated electricity to produce hydrogen. Wind-energy does not appear to be an alternative to traditional large-scale energy sources at this time.

b. Conversion Techniques

1. Fuel Cells

Fuel cells are electrochemical devices in which the chemical energy of fuel is converted continuously and directly to low-voltage direct current electricity. The basic process is similar to that of a battery except that the fuel cell is an open system requiring a continuous supply of reactants for the production of electricity. Their potential advantages over more conventional energy conversion systems are their quietness, low temperature of operation, minimization of pollution, reliability, and greater efficiencies. Nearly one and one-half times more electrical energy can be obtained from a ton of coal in a fuel cell system than for a comparable amount burned in a modern conventional power system.

By direct conversion of the chemical energy into electrical energy and elimination of the thermal energy to mechanical energy steps in conventional power generation, fuel cells promise greater efficiency on the order of 50-55%. Their theoretical efficiencies are even higher, but the 50-55% compares favorably with 32-40%for steam electric power plants through nuclear, oil, gas, or coal.

The concept is particularly favorable from the pollution aspects as shown below.

Table VIII-5

COMPARATIVE POLLUTION LEVELS 1/
(pounds per 1,000 kwh produced)

	Gas-fired Central Station	Fuel Cells 2/
Sulfur dioxide........	0.3	0.0003
Nitrogen oxides.......	4.0	0.24
Hydrocarbons..........	2.8	0.23
Particulates..........	0.1	0.00003

1/ Energy Research Needs, Schurr, S. H., Resources for the Future, Inc., October, 1971.

2/ Design features based on data from experimental fuel cells.

The chemical output from fuel cells consists primarily of water and carbon dioxide. Due to the relatively high efficiency, thermal pollution is low.

A number of cells are connected on a series-parallel circuit to produce the desired voltage and power output. This is advantageous in that transformers can be eliminated with any desired voltage and power output obtained by building various combinations of basic units.

The disadvantage of the fuel cells is a matter of economics. Present costs are about $400/kw compared to $250-350/kw for future central station generation. Two costs not incurred by fuel cells are transmission costs from the central station and reserve capacity costs. Nevertheless, at $400/kw, a 12.5 kw installation would cost $5,000 and a householder would not likely make this investment when almost no investment is required for central station power. Fuel cells produce direct current and must be fed into an inverter to convert it to alternating current used by most appliances. This adds to the cost. Metal catalysts and fuel purification processes are also partially responsible for the high capital cost and high operating costs.

Since the middle 1950's, hundreds of U.S. and foreign companies have conducted research and development on fuel cells. Successful fuel cells for aerospace (Gemini and Apollo) were developed. Commercial applications on vehicular power, central power, and residential gas total energy have been less successful. The two remaining commercial development programs for off the road vehicles and a gas fueled total energy fuel cell package are unlikely to have a significant effect on fuel use by 1985 since they lack both efficiency and investment advantages over prospective magnetohydrodynamic-topped or thermionic-topped fossil-fuel or nuclear generating stations.

Fuel cells do have some potential environmental advantages such as quietness, low operating temperatures and absence of toxic wastes and the use of fuel cells in localized substations could reduce the need for central station power and transmission lines.

However, unless major new developments occur in fuel-cell technology (unlikely, considering the vast amount of work completed), fuel cells will have little impact on fuel utilization by the end of the century. Should reformer types be developed, normal fuel supply economics will determine which fossil fuel is affected. In any case, the gain in fuel efficiency over conventional converters would be small (10-15%). A breakthrough in direct use of hydrocarbons or in producing pure fuels such as methanol or hydrazine at low cost might have larger impact on fuel efficiency, but it is not likely that these developments will materialize in the near future.

2. Magnetohydrodynamics

Magnetohydrodynamics (MHD) power generation is a technique for electrical generation which passes a hot ionized gas, or liquid metal, through a magnetic field. Such a high temperature one-stage conversion device has the potential of high overall efficiencies. Though the concept of MHD generation has been known for over 100 years, it is only during the past decade that significant technological advances have produced systems which offer promise for use in the electric power field. Three basic approaches to MHD generation are being explored--open-cycle, closed-cycle and liquid metal systems.

The MHD open-cycle generation, used as a"topping unit" in conjunction with steam-turbine generation, appears to hold the most promise for MHD central-station power generation in the future. Overall system efficiency is expected to increase to a range of 50 to 60 percent, which could provide a fuel saving of 20 to 30 percent over fossil fuel steam-electric plants. General application of coal-fired MHD topping units by the mid 1980's could effectively extend fossil fuel reserves and enhance the potential for use of coal for power generation. Since the MHD generator would require little cooling water, the combined MHD-steam units would require considerably less cooling water per megawatt of capacity than conventional fossil fueled or nuclear steam-electric units.

Before MHD can be utilized for central power station generation, there are many significant technological problems which must be solved. No economically practical system has yet been demonstrated for burning coal or coal-derived fuels. Designs to date have been small scale with short life-times and lower efficiencies than would be required for utility operation. There are problems of developing long-life MHD channels and electrodes, high temperature preheaters, super-conductivity magnets, seed recovery systems, high temperature metal erosion and corrosion, etc. The high temperatures and gas passage time are conductive to fixation of nitrogen so there may be significant NO_x air quality problems.

MHD research presently is being conducted in England, France, Germany, Japan, Poland, the Soviet Union and the United States. The Soviet Union appears to have made a strong commitment to the development of MHD for commercial use. Soviet engineers express confidence that an open-cycle MHD unit of appreciable power output will be operating in the 1970's but there is yet no evidence of proven economic feasibility. A 75 MW combination MHD steam pilot plant (25 MW MHD and 50 MW steam) is being constructed near Moscow. For the present, only a 25 MW portion of the plant currently is planned for completion and operation. Japan also has made great strides in achieving the high field super conductivity magnets necessary for MHD.

Utility companies, manufacturers, research institutions, and the U.S. Government have been actively involved in MHD investigations since the 1950's. A 1969 Office of Science and Technology report identified many problem areas in which research and development are needed before MHD power system work can proceed to a full-scale prototype. This report recommended that the U.S. Government encourage work on solving the difficult problems of coal-burning open-system MHD systems. In January 1973, at least four relatively modest U.S. efforts on magneto-hydrodynamics were continuing although only one related to practical power generation.

While MHD appears to offer considerable future potential for coal-fired power generation, the technologic and economic uncertainties are still so great that it cannot be considered as a viable alternative power source by 1980. Combustion products from fuels such as petroleum distillates and natural gas give low electrical conductivity in MHD ducts. The thermal efficiency of MHD topped plants with petroleum fuels is significantly lower than with coal or coal gas as a fuel. Improvements in the combined Brayton-Rankine cycle, which are likely to occur before 1985, offer serious competiton for MHD and has dampened the electrical equipment and utility industries interest in MHD conversion for the present.

It appears that the MHD concept can first emerge as a peaking or emergency power plant with distillate or residual fuels. With adequate funding, a large prototype peaking plant might be available by 1978.

For MHD to be applicable to base load plants fired by coal, a long-term and costly program extending beyond 1982 seems likely. Even if sufficient funding occurs, some probability exists that engineering problems will not be solved in a way that will be practically or economically acceptable. While competitive and lower capital costs have been projected for MHD-topped steam plants, reliable economics must await the demonstration of MHD on a large-scale for long duration. Base load MHD-topped plants fired by coal are far from successful development. Since peaking plants have only a small effect on our total energy requirements, no significant effect from MHD seems likely before 1985.

Environmental Considerations

Increased thermal efficiency would reduce the overall amount of fossil fuel requirement per unit of energy produced which would reduce that amount of pollution associated with the fossil fuel production. The reduced water cooling requirement would result in less thermal pollution impacts on water quality. The wide distribution of coal resources and reduced cooling water demand would promote location of generation stations near the coal resource and population centers, thereby reducing long distance electrical energy transmission requirements or coal transportation. Reduced fuel consumption would result in a lower volume of noxious effluents than would be discharged into the atmosphere by a comparable capacity of conventional power plants.

While there still could be air pollution problems similar to those of other coal uses, increased NO_x problems resulting from high temperature operations also might develop. If coal demand should increase it would require a corresponding increase in surface or subsurface coal mining with the inherent environmental impacts of such mining. While generators could be located close to coal deposits, there would be environmental disruptions associated with transportation from mine to generator, additional transmission lines, development and operation of power station sites, and possible noise problems.

3. Thermoelectric

When two dissimilar metals are joined together in the form of a loop and one of the junctions is held at higher temperature, an electric current will flow. With possible efficiencies in generator technology in the order of 30%, it appears that overall efficiencies of thermoelectric systems could not exceed 10 to 15 percent. Short operating life-times, which result from the instability of thermoelectric elements at high temperatures necessary for higher power operations, and undesirable heat transfer from the hot to cold junctions, which result in low efficiencies, are major obstacles to additional progress in development of this electric energy source. Although thermoelectric generation will doubtless receive continued attention for special low power applications, it would seem to hold little potential for central power station plans in the foreseeable future.

4. Thermionic Generation

Thermionic conversion of heat directly to electricity depends upon the emission of electrons from metal surfaces at very high temperatures--typically near 3,000°F. The electrons are collected on another closely spaced (0.005 in.) metal surface at lower temperature, typically 1,100-1,600°F. The device is called a diode, from its close analogy to electronic vacuum tubes. Commonly, the emitter and collector are concentric refractory metal tubes several inches long. They may be constructed in electrical series connection to multiply the 0.7 to 1.0 output voltage of single diodes. Heat may be supplied by fossil fuels or by nuclear fuels and may be transmitted to the emitter either directly or indirectly, as by a "heat pipe".

Since thermionic generators are another type of heat engine, their efficiency theoretically is limited to 35-40%, but the best realized efficiencies are below 20%, at operating temperatures near 3,000°F. Laboratory system efficiencies do not now exceed 10%. Commercial exploitation of the phenomenon awaits solution of difficult materials problems related to operations above 3,000°F. and in radiation damage to isotopic-fueled devices. The Federal Power Commission 1972 National Power Survey indicates that the concensus is that future efforts in thermionic development during the next decade will be concentrated in space oriented activities. The principal effort will be directed to the development of nuclear-fueled systems to be used as power sources for interplanetary expeditions. Even assuming materials problems will be conquered, there is little likelihood of thermionics achieving commercial realization for large scale generation by 1985. This is largely due to the high capital costs of the thermionic system for topping a conventional fossil fuel or nuclear generating system. However, increased fuel efficiency could make them economically attractive and a recent estimate suggests that thermionic topping, would about break even with incremental conventional generating capacity in a modern super critical coal fueled station.

In January 1973, there were at least 11 large scale research projects in thermionic generation funded by various private, governmental, or military groups.

Thermionic development is not sufficiently advanced for an evaluation of potential environmental impacts. Since it is a type of heat engine, the associated heat is a potential source of thermal pollution although coupled into a total energy system it could be used to diminish heat pollution. Its primary advantage lies in reducing the necessity of using fossil fuels by increasing their efficiencies.

9. Combination of Alternatives

In the interest of clarity of presentation this analysis has discussed separately each potential alternative form of energy as possible substitute to the oil and gas anticipated from the proposed sale. It is highly unlikely that there will ever be a single definitive choice to be made between any potential energy form and its alternatives. Each may have a role to play; some may make major contributions to our energy supplies, while others may be subordinated to lesser roles. Some alternatives may be developed rapidly; others may evolve more slowly-perhaps to make a more important contribution at a later date. Forecasting on the basis of present knowledge of the relative roles of these potential alternatives is a highly subjective exercise which must necessarily include a large measure of judgment as to future trends in such variables as the direction and pace of technological development, the identification of usable resources, the rate of national economic growth and changes in our life style.

The table which follows this section summarizes the pertinent data developed in other sections of this statement as to the possible alternatives to provide the energy equivalent to that projected for the proposed sale. Examination of this table will facilitiate consideration of possible combinations of alternatives.

It seems most probable that many of the alternatives outlined in the table will be developed to some degree. Understanding of the extent to which they may replace or complement offshore oil and gas requires reference to the characteristics of our total national energy system. Factors most relevant to the issues at hand are outlined below:

1. Historical relationships indicate that energy requirements will grow at approximately the same rate as gross national product.

2. Energy requirements can be constrained to some degree through the price mechanisms in a free market or by more direct constraints. One important type of direct constraint operating to reduce energy requirements is through the substitution of capital investment in lieu of energy; e.g., insulation to save fuel. Other potentials for lower energy use have more far-reaching impacts and may be long range in their implementation--they include rationing, altered transportation modes, and major changes in living conditions and life styles. Even severe constraints

on energy use can be expected to only slow, not halt, the growth in energy requirements within the time frame of this statement.

3. Energy sources are not completely interchangeable. Solid fuels cannot be used directly in internal combustion engines; for example; fuel conversion potentials are severely limited in the short term although somewhat greater flexibility exists in the longer run and generally involves choices in energy-consuming capital goods.

   The principal competitive interface between fuels is in electric powerplants. Moreover, the full range of flexibility in energy use is limited by environmental considerations.

4. A broad spectrum of research and development is being directed to energy conversion--more efficient nuclear reactors, coal gasification and liquefaction, liquified natural gas (LNG), and shale retorting, among others. Several of these should assume important roles in supplying future energy requirements, though their future competitive relationship is not yet predictable.

5. Major potentials for filling the supply/demand imbalance for domestic resources are:

   - More efficient use of energy
   - Environmentally acceptable systems which will permit production and use of larger volumes of domestic coal.
   - Accelerated exploration and development of all domestic oil and gas resources.
   - Development of the Nation's oil shale resources.

   Of the foregoing increased domestic oil and gas production offers considerable possibilities, since indicated and undiscovered domestic resources total 417 billion barrels of oil and 2,100 trillion cu.ft. 1/ of gas which are estimated to be producible under current technology. However, the feasibility of providing adequate incentive and reducing the uncertainties inherent in petroleum exploration is not known.

6. The acceptability of oil and gas imports as an alternative is diminished by:

   - A narrowing gap between costs of foreign and domestic oil.

1/ USDI, United States Energy: A Summary Review, pp. 22 and 27.

- Apparent high costs of liquefying and transporting natural gas other than overland by pipeline.
- The security risks inherent in placing reliance for essential energy supplies on sources which have demonstrated themselves to be politically unstable and prone to use interruption of petroleum supplies to exert economic and political pressure on their customers.

  The aggravation of unfavorable international trade and payments balances which would accompany substantial increases in oil and gas imports.

Though this section considered the possibility of combinations of alternatives, in view of the foregoing it seems reasonable to postulate that for some time to come the basic alternative to the production of the oil and gas from the sale would be an equivalent amount of foreign imports. This would be true whether it is considered as an alternative to the entire proposed sale or to any number of tracts deleted from the sale. The problems associated with this alternative have been discussed in the text. Although an equivalent amount of imports appear to be the basic alternative for the foreseeable future (ten to fifteen years), it is difficult to predict what alternatives, or combinations of alternatives, would be feasible in the more distant future. The availability of other alternatives in the more distant future is discussed elsewhere in the text.

Incremental Production from Different Alternatives to Provide the Energy Equivalent of Proposed Lease Sale

Equivalent Production or Maximum Projected Production

	1980		1985	
Alternative	Physical Units	Btu (billions)	Physical Units*	Btu (billions)
Proposed MAFLA Sale				
Oil	270-443 mbbl/d	1,566-2,569	270-443	1,566-2,569
Gas	340-520 mmcf/d	351-537	340-520	351-537
Oil Imports	331-536 mbbl/d	1,917-3,106	331-536	1,917-3,106
LNG Imports 1/	1,860-3,010 mmcf/d	1,917-3,106	1,860-3,010	1,917-3,106
Onshore Production 2/				
Oil	270-443	1,566-2,569	270-443	1,566-2,569
Gas	340-520	351-537	340-520	351-537
Deregulation of Wellhead Price of Natural Gas	Uncertain		Uncertain	

*Physical Units in this column are the same as those on the same line in first column.

1/ Assuming development of a LNG industry with construction of terminal and regasification facilities.

2/ Assuming economic incentives.

Cont'd

Coal as Solid Fuel	29-47 million Tons/yr	1,917-3,106	29-47	1,917-3,106
Oil Shale 1/	150,000 bbl/d	870	750,000	4,350
SNG 2/	1,920 mmcf/d	1,980	1,920 mmcf/d	1,980
Hydroelectric	Negligible		Negligible	
Nuclear	11-18 thou. MW	1,917-3,106	11-18 thou. MW	1,917-3,106

1/ National Petroleum Council projections under the most optimistic case.

2/ Department of the Interior, Bureau of Mines projections.

C. Delay Sale

1. Until New Technology is Available to Provide Increased Environmental Protection

The sale could be delayed until new technology is available; however, basically safe technology is available provided its application and use are properly regulated and controlled. As new technology relating to safety and environmental protection is developed, it can be incorporated with existing requirements and applied to all OCS leases so that bringing on additional production now will not generally preclude adaptation of new advances to the prospective leases. "Zero risk" does not exist but is an idea toward which safety systems are directed. In the history of Federal offshore leasing and production over the past 19 years only 11 spills of 1,000 bbl. or more have occurred in more than approximately 1,500 leases, 10,500 drilling holes and 1,939 producing platforms.

2. Pending Completion of Studies Concerning the Potential Environmental Impacts of Offshore Minerals Development in General and Oil Spills Specifically

The proposed sale could be delayed pending completion of all studies concerning the potential environmental impacts of offshore minerals development in general and oil spills specifically. Many long-term, ongoing studies relating to these issues are being conducted by the scientific community, industry and government. The Bureau of Land Management is initiating long-term, ongoing studies of its own both on an inhouse and contract basis. See Section I for a description of the Bureau's present study efforts relating to the OCS program.

A central feature of many of these studies is that they are never really completed in the sense that they rarely reach definitive conclusions with wide applicability, but simply advance from one stage to another, from one level of analysis to another, thereby contributing to a growing area of knowledge and body of literature pertaining to the numerous complexities of environmental analysis. To delay the sale on the basis of incompleted studies would require an indefinite delay perhaps of many years duration. As the recent University of Oklahoma study: "Energy Under the Oceans: A Technology Assessment of Outer Continental Shelf Oil and Gas Operations", points out, current and programmed research on OCS environmental data will help improve our knowledge, however, acquiring a total functional understanding of the coastal environment is an "extremely long-term goal". Undoubtedly, information gaps and uncertainties will always be associated with offshore minerals development and any delays in such a development program must be judged on the basis of whether or not these gaps and uncertainties are so great, compared with what is known, as to warrant postponement. The President, in his Energy Message of April 18, 1973, directed the "Secretary of the Interior to take steps which would triple the annual acreage leased on the Outer Continental Shelf by 1979, beginning with expanded sales in 1974 in the Gulf of Mexico. . ." This will help make available increased supplies of energy resources of Federal lands for national energy needs. Final judgment must rest on a determination regarding whether or not a delay in this proposed lease sale, would be in the nation's best interest.

3. Pending Development of Land-Use and Growth Plans Onshore

The proposed sale could be delayed pending the development of land-use and growth plans onshore. Florida, for example, anticipates that a growth plan will be available in 1974. Timetables for onshore development plans differ from state to state in terms of initial development of plans, updating, revisions, and subsequent implementation. Delay of the sale awaiting such plans could cause the development of the offshore mineral resources in a piecemeal, unorderly manner. It could result in a greater degree of coordinated planning between states and the Federal Government especially with regard to coastal areas and would result in the avoidance of potential environmental impacts resulting from lack of coordinated efforts. It should be stated, however that onshore development must take place within the authority of state and local government agencies and coordination with the jurisdictional agencies is sought throughout the entire leasing and development process.

4. Pending Completed Implementation of Recommendations Made in Reports on OCS Operating Orders and Regulations and a Review of Regulations and Amendment as Necessary

A decision could be made to delay this sale until the implementation of those recommendations made in reports concerning strengthening operating procedures discussed in Vol. 1., Sec. I.H.2 had been completed. During the implementation of these recommendations a review could be completed of all operating and leasing regulations, OCS orders and statutory provisions to locate sections that needed revision. Any necessary amendments of the regulations and orders could be made through the appropriate procedures and if sections of the OCS Act were found to need revision, amendments could be suggested to Congress. In considering this alternative the existing authority of the OCS Act to prescribe and amend regulations at any time when the Secretary determines it to be necessary and proper so as to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf and the protection of correlative rights therein must be kept in mind. 43 U.S.C. § 1334(a)(1). Any revisions of the operating regulations or the OCS orders which related to the prevention of waste, conservation of natural resources, or protection of correlative rights could be made at any time and apply to all existing leases. It is unlikely, however, that amendments to the OCS Act or regulations dealing with matters other than the above could be applied to leases in existence at the time of the amendment. If such amendments were felt necessary for leases which may be executed if the proposed sale takes place, they would have to be done before the leases are signed by the parties.

Environmental Impact of A Decision to Delay the Sale

A decision to delay the sale based upon any combination of the four reasons given above would eliminate any environmental impact to the offshore or onshore area of the sale during the period of delay. The environment of the area would exist during the delay essentially as it does today. Assuming a decision was made to hold the sale at a future date after all the reasons for delay had been satisfied, the environmental impact would reflect the degree of success achieved in obtaining more fail-safe technology, baseline biological data against which the potential impacts could be assessed, land-use development plans with which operations could be coordinated, and revised leasing and operating regulations and orders to strengthen the management of OCS operations and minimize the impact of such operations.

It is conceivable that the potential environmental impact of operations resulting from a sale held after such a delay would be of much the same character as those potential impacts discussed in this statement but that the potential for such impacts occurring would be minimized. Some impacts might be reduced entirely if changes in operating techniques were the result of the review conducted during the delay period. For instance, biological baseline data and other research might suggest that drilling muds are harmful when released into the marine environment. If such findings were made, different operating procedures would no doubt result to eliminate or reduce this impact. Such different operating procedures would have their own environmental impact which would have to be considered.

If this sale were delayed for the reasons given it is evident that the delay would be for more than just a few months. A delay of at least two years could reasonably be expected to complete baseline studies, develop improved technology, implement land use programs - particularly under the Coastal Zone Management Act, and implement the recommendations and regulatory changes discussed above. In the event of a delay of that duration, alternative energy sources would be expected to fill the gap left in the needed energy supply during that period. These alternative energy sources have their own environmental impact as discussed earlier in this section of the statement. Depending upon the alternative source or combination of sources drawn upon to meet the demand left unsatisfied by the delay in this sale, the environmental impact to the nation could be more or less than that anticipated from this sale.

Other than these general statements concerning the environmental impact of delaying this sale it is difficult to determine the precise impacts should the sale be held at some later date. The changes that might be made in a later sale are speculative at this stage because of uncertainty as to baseline data that would be gathered, improvements in technology, and revised regulations that could result. It can be said with certainty, however, that prior to deciding to hold a sale at a later date, the environmental impact would be thoroughly assessed.

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